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ZARGON
ENERGY TRUST

COMMITTED TO SUSTAINABILITY

2006 Annual Report

ZARGON HIGHLIGHTS

	2006	2005	Percent Change
FINANCIAL			
Income and Investments ($ million)			
Petroleum and natural gas revenue	**154.04**	162.72	(5)
Funds flow from operations	**83.52**	84.97	(2)
Cash distributions	**35.90**	37.44	(4)
Net earnings	**44.50**	35.37	26
Net capital expenditures	**63.37**	54.68	16
Per Unit, Diluted			
Funds flow from operations ($/unit)	**4.34**	4.51	(4)
Net earnings ($/unit)	**2.68**	2.19	22
Cash Distributions ($/trust unit)	**2.16**	2.32	(7)
Balance Sheet at Year End ($ million)			
Property and equipment, net	**283.11**	253.32	12
Bank debt	**30.04**	10.34	191
Unitholders' equity	**165.56**	144.61	14
Total Units Outstanding at Year End (million)	**19.42**	18.99	2
OPERATING			
Average Daily Production			
Oil and liquids (bbl/d)	**3,805**	3,697	3
Natural gas (mmcf/d)	**27.70**	27.87	(1)
Equivalent (boe/d)	**8,422**	8,342	1
Equivalent per million trust units (boe/d)	**437**	445	(2)
Average Selling Price (before the impact of financial risk management contracts)			
Oil and liquids ($/bbl)	**61.25**	57.15	7
Natural gas ($/mcf)	**6.82**	8.41	(19)
Proved and Probable Reserves at Year End			
Oil and liquids (mmbbl)	**15.93**	15.35	4
Natural gas (bcf)	**69.15**	68.50	1
Equivalent (mmboe)	**27.46**	26.77	3
Equivalent per total unit (boe)	**1.41**	1.41	–
Wells Drilled, Net	**76.2**	53.5	42
Undeveloped Land at Year End (thousand net acres)	**381**	367	4

NOTES:

Throughout this report, the calculation of barrels of oil equivalent (boe) is based on the conversion ratio that six thousand cubic feet of natural gas is equivalent to one barrel of oil. For a further discussion about this term, refer to the Management's Discussion and Analysis section in this report.

For net capital expenditures, amounts include capital expenditures acquired for cash and equity issuances.

Total units outstanding include trust units plus exchangeable shares outstanding at year end. The exchangeable shares are converted at the exchange ratio at the end of the year.

Funds flow from operations is a non-GAAP term that represents net earnings except for non-cash items. For a further discussion about this term, refer to the Management's Discussion and Analysis section in this report.

Average daily production per million trust units is calculated using the weighted average number of units outstanding during the year, plus the weighted average number of exchangeable shares outstanding for the year converted at the average exchange ratio for the year.

For Zargon, committing to sustainability means that over the long term we must maintain reserves, production and cash distributions on a per trust unit basis without sacrificing the underlying quality of the Trust's assets or financial condition, while distributing approximately 50 percent of the funds flow from operations attributed to our unitholders. This sustainability objective is to be accomplished with ongoing oil and natural gas exploration, development and exploitation capital programs funded by the remainder of our Trust's funds flow from operations.

ZARGON HAS A RICH HISTORY OF DISCIPLINED, VALUE-ORIENTED OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT AND EXPLOITATION, WHICH PROVIDES A SOLID FOUNDATION FOR OUR SUSTAINABLE OIL AND NATURAL GAS TRUST MODEL.

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THE YEAR IN BRIEF

Zargon Energy Trust reported strong financial and operating results in 2006, during its second full year of operations in a sustainable trust format. The year was highlighted by funds flow from operations of $83.52 million or $4.34 per diluted trust unit, a small decline from the prior year's $4.51 per diluted trust unit. During 2006, the Trust distributed $35.90 million to unitholders ($2.16 per trust unit) which was equivalent to payout ratios of 50 percent on a diluted trust unit basis or 43 percent of funds flow from operations (exchangeable shares do not receive distributions).

On October 31, 2006, the Canadian Federal Government announced new regulations that may significantly reduce the tax advantages of our current trust structure after 2010. As this date approaches, management will evaluate and choose the appropriate structure that will permit Zargon to meet its value creating objectives.

Operationally, Zargon had a record year of activity in 2006 with net capital expenditures of $63.37 million, a 16 percent increase from the prior year. Production volumes for the year increased by one percent to 8,422 barrels of oil equivalent per day and are projected to increase modestly again in 2007. On October 31, 2006, the Canadian Federal Government announced new policies pertaining to the taxation of Canadian income trusts commencing in 2011, which if enacted could have a significant impact on Zargon. Despite this development, *Zargon enters 2007 in the enviable position of having a very strong balance sheet, a large opportunity base of exploration, development and exploitation programs and a long successful history of significant value creation through internally generated oil and gas activities.*

COMMITTED TO SUSTAINABILITY

Throughout Zargon's fourteen-year history, our fundamental objective has been to create value for equity holders through oil and gas exploration, development, exploitation and acquisition activities in the Western Canadian and Williston sedimentary basins. We seek to provide superior long term financial returns through the use of our organization's professional skills and oil and gas industry knowledge, while protecting our equity holders' existing capital by incorporating fiscally conservative policies.

In July 2004, we converted into a sustainable trust structure in order to continue our business plan in a more tax efficient manner. Zargon Energy Trust was created through the acquisition of all of the operational, financial and intellectual assets of our predecessor company, Zargon Oil & Gas Ltd. The Trust was structured in a format that is designed to sustain its operations while distributing approximately 50 percent of the funds flow from operations.

Zargon seeks to provide superior long term financial returns through the use of our organization's professional skills and oil and natural gas industry knowledge, while protecting our equity holders' existing capital.

For Zargon, this sustainability objective translates into annually providing stable or improved metrics on a per trust unit basis for reserves, production and cash distributions. In addition, sustainability must not be accomplished through the deterioration of the underlying quality of assets, the Trust's financial condition or the acceleration of the Trust's taxability horizon. Due to the significant variability in our industry's operating environment, it may not be possible to simultaneously maintain stable results for each of these metrics in any one year, but over a multi-year period we expect to deliver modest per unit growth in general and stability for each of the metrics.

Zargon is committed to the sustainable trust model as we believe it is an appropriate structure for a small-intermediate sized oil and gas producer in this relatively mature Western Canadian sedimentary basin. With the commitment to deliver regular cash distributions, the structure provides the economic tension that encourages efficient capital programs, as surplus cash flow need not be reinvested in capital programs, but can be efficiently returned to equity holders.

OUR 2006 RESULTS

Flowing from the sustainable trust model, the objectives for the organization are to annually provide stable or improved metrics for the following:

- Reserves per trust unit;
- Production per trust unit;
- Cash distributions per trust unit;
- Balance sheet quality.

In 2006, Zargon was able to maintain total proved and probable reserves at 1.41 barrels of oil equivalent per total unit. With a 50 percent cash distribution policy, the sustainability mathematics imply that we must strive to add two barrels of oil equivalent reserves from our exploration and development programs that are funded by the cash flow derived from each barrel of oil equivalent produced. This recycle ratio (defined as the Trust's funds flow from operations on a barrel of oil equivalent basis divided by proved and probable finding and development costs on a barrel of oil equivalent basis) of two times is therefore a fundamental target of our Trust. In 2006, Zargon's recycle ratio was negatively impacted specifically by negative natural gas reserve revisions in the West Central Alberta core area and in general by

HISTORY OF VALUE CREATION AND RETURNS

Throughout our fourteen-year history, Zargon has successfully focused on a value creation strategy as evidenced by the following statistics:

- Fifty-three consecutive quarters of positive net earnings.
- Over our history, Zargon has issued $53.3 million of equity for cash or property. Including the February 2007 cash distribution, Zargon has returned $90.1 million back to its unitholders, while building a business entity with a market capitalization of approximately $500 million.

2006 KEY SUSTAINABILITY METRICS

Zargon defines its sustainability targets in terms of the following six parameters:

- **PRODUCTION:** Zargon's production averaged 437 barrels of oil equivalent per day per million trust units, a two percent decline from last year's rate of 445 barrels of oil equivalent per day per million trust units.
- **RESERVES:** Zargon's year end proved and probable reserves were 1.41 barrels of oil equivalent per total unit, unchanged from the prior year.
- **DISTRIBUTIONS:** Cash distributions were $2.16 per trust unit, a seven percent decline from the prior year's $2.32 per trust unit distribution that had been fuelled by record natural gas prices.

increased costs throughout the industry. In 2006, the Trust's recycle ratio (including allowance for future development costs) was 1.33 resulting in a three-year average recycle ratio of 1.59. Despite these somewhat disappointing results in 2006, Zargon remains committed to the long term delivery of a two times exploration and development recycle ratio.

In addition to maintaining stable reserves per trust unit, the sustainability commitment requires Zargon to maintain production rates on a per trust unit basis. In 2006, production averaged 437 barrels of oil equivalent per day per million trust units. This represents a two percent decline from last year's rate of 445 barrels of oil equivalent per day per million trust units. Maintenance of our production base requires efficient exploration and development programs to add new production to replace the declining production rates from existing properties. By taking the inverse of Zargon's proved producing reserve life; we infer an annual 2006 production decline rate of 19 percent. This implies that Zargon must add approximately 1,600 barrels of oil equivalent per day of new production every year to replace the naturally occurring production declines. Using this calculation methodology, Zargon's 2006 exploration and development program replaced production volumes at $42,620 per barrel of oil equivalent per day compared to $33,500 per barrel of oil equivalent per day in 2005. Similar to the reserve replacement requirements, efficient production addition costs are a key benchmark that we use to evaluate our exploration and development programs. *In 2007, we anticipate improved production addition metrics as we proceed with the tie-in of natural gas wells from our expanded fourth quarter 2006 Alberta Plains and West Central Alberta core area capital programs.*

Throughout 2006, Zargon maintained its base distribution at $0.18 per trust unit per month resulting in total cash distributions for 2006 of $2.16 per trust unit. This compares to $2.32 per trust unit in 2005, which included a supplemental distribution in December 2005 of $0.50 per trust unit. Embedded in our sustainable base monthly distribution policy of $0.18 per trust unit, are our current production guidance volumes and our long term hydrocarbon commodity price assumptions of US $55 per barrel (WTI oil), US $7.50 per mmbtu (NYMEX natural gas) and an $0.87 Cdn/US dollar currency exchange rate. When commodity prices exceed our long term commodity price assumptions, Zargon will consider declaring, on a semi-annual basis, supplemental distributions to reach our stated goal of distributing approximately 50 percent of the Trust's funds flow from

Zargon's relatively low debt level provides an excellent opportunity to deliver superior 2007 results from active exploration, development, exploitation and acquisition programs during a period of reduced competition and improved value creation prospects.

operations attributed to our unitholders. Conversely, if commodity prices fail to meet these long term commodity price assumptions, Zargon will have to recalibrate its sustainability model, which would likely result in a reduction in the base distribution levels per trust unit.

Zargon's debt net of working capital (excluding unrealized risk management assets and liabilities) of $39.83 million at December 31, 2006 was equivalent to 48 percent of the 2006 funds flow from operations, a significant increase from the 32 percent level of the 2005 funds flow from operations at December 31, 2005. Zargon's net debt levels increased during the second half of the year due to a very active fall-winter natural gas exploration and development capital program that is now delivering material production gains in the first half of 2007. Zargon's net debt levels still remain at very low levels compared to our oil and gas trust industry peers. This relative advantage provides Zargon an excellent opportunity to deliver superior 2007 results from active exploration, development, exploitation and acquisition programs during a period of reduced competition and improved value creation prospects. Although we anticipate that Zargon's relative net debt levels will once again increase in 2007 as we work in a potentially lower cost environment, Zargon remains committed to preserving a strong balance sheet as a fundamental principle of our sustainable trust strategy.

MODE OF OPERATIONS

Throughout our history, Zargon's success has been facilitated by the efficient exploitation of oil properties and seismically-driven exploration and development of natural gas properties. Our large inventory of underdeveloped oil properties and undeveloped natural gas prospective land provides Zargon the resource base to support these activities.

Our oil exploitation business begins with the identification and acquisition of properties with large oil-in-place that are primarily located in the Williston Basin core area. We then deploy improved recovery techniques or geologically-driven exploitation concepts to develop additional reserves. Through numerous historical acquisitions and associated drilling and development programs, Zargon has assembled a Williston Basin working interest inventory of 182 million barrels of exploitable oil-in-place.

2006 KEY SUSTAINABILITY METRICS (CONT'D)

- **BALANCE SHEET QUALITY:** Zargon's 2006 year end debt net of working capital (excluding unrealized risk management assets and liabilities) of $39.83 million represented a debt to funds flow multiple of approximately 0.5 years, up from the prior year's comparative of 0.3 years.
- **ASSET QUALITY:** Zargon's asset quality in terms of average crude gravity (30 degrees API), and natural gas/oil mix (55 percent natural gas production) did not change materially in 2006. The year end proved producing, proved total and proved and probable reserve life indices also remained essentially unchanged at 5.4, 6.2, and 9.0 years, respectively.
- **TAX HORIZON:** Zargon's quantity of tax pools increased in 2006 to a year end balance of approximately $113 million, compared to the 2005 year end balance of $90 million.

2006 OPERATING HIGHLIGHTS

Net capital expenditures in 2006 totalled $63.37 million, with $66.51 million allocated to exploration and development activities.

- Drilled a 76.2 net well program, with a 95 percent success rate, that delivered 47.7 net natural gas wells and 22.5 net oil wells.
- Total production increased one percent to 8,422 barrels of oil equivalent per day.
- Zargon's 2006 capital investment program replaced production by 94 percent (proved reserves) and 122 percent (proved and probable reserves).
- Proved and probable reserves increased three percent to 27.46 million barrels of oil equivalent. Proved and probable finding, development and acquisition ("FD&A") costs were $20.44 per barrel of oil equivalent (inclusive of the change in future development costs) which resulted in a 2006 trust recycle ratio of 1.33 times.

Our natural gas exploration business targets shallow and medium depth higher rate natural gas reservoirs in both the West Central Alberta and Alberta Plains core areas and is based on seismic, geological and reservoir engineering concepts. Our natural gas development business targets the development of lower rate natural gas reservoirs in the Alberta Plains core area through efficient multi-well capital programs. *For both our exploration and development natural gas strategies, we seek to acquire large contiguous land blocks with multi-zone potential where preferably we control natural gas facilities.* We reduce exploration risk by applying advanced seismic and detailed geological mapping. We improve our gas development program returns through capital program efficiencies and cost containment. Based on prior property and Crown land acquisition programs, Zargon continues to hold a large inventory of 381 thousand net acres of undeveloped land that provides the foundation for our natural gas exploration program. Furthermore, with last year's changes to the Alberta Energy and Utilities Board regulations regarding down-spacing and commingling, our development program inventory has been replenished providing Zargon with a multi-year natural gas development drilling inventory at the Jarrow and Hamilton Lake properties of the Alberta Plains core area.

In 2006, Zargon achieved strong operating results and met sustainability objectives in two of its three core areas. The Alberta Plains core area team was able to increase production and reserves at year end with a capital reinvestment program of $22.95 million (60 percent of core area cash flow). Alberta Plains core area proved and probable finding, development and acquisition ("FD&A") costs averaged $18.03 per barrel of oil equivalent in 2006 and were primarily driven by Jarrow drilling successes. In 2007, a similar capital program is planned, but with an increased emphasis on down-spacing development projects for the Jarrow and Hamilton Lake gas properties along with exploitation of the Taber oil property.

In the Williston Basin core area, we saw similar success in 2006 with production growing six percent from a $22.13 million capital program (52 percent of core area cash flow) and proved and probable FD&A costs of $15.99 per barrel of oil equivalent. Specifically, high rate and large reserve wells were added at the Pinto, Elswick and Steelman, Saskatchewan properties and the Haas and Truro properties in North Dakota. Also, consistent with prior year's historical pattern of positive Williston Basin reserve revisions, 0.36 million barrels of oil equivalent of proved and probable reserve revisions were recognized. These revisions were primarily due to

In addition to our sustainability objectives for our internally generated capital programs, our business strategy envisions a modest level of growth, on a per trust unit basis, to be provided by corporate and property acquisitions.

increased reservoir recovery factors recognizing the positive performance pertaining to waterflood modifications or implementations. In 2007, Zargon plans to continue its successful Williston Basin capital programs by focusing on comprehensive development programs at the Elswick, Pinto and Steelman properties in Saskatchewan.

Although experiencing improved 2006 exploration results, the West Central Alberta core area showed higher than anticipated production declines from prior discoveries that in turn resulted in negative natural gas reserve revisions. With a capital program of $18.29 million (136 percent of core area cash flow), production declined by three percent from the previous year. Proved and probable FD&A costs were a disappointing $59.19 per barrel of oil equivalent, due to 3.8 billion cubic feet of negative natural gas reserve adjustments related to the Sturgeon Lake, Highvale, Judy Creek and Progress properties. Excluding the impact of reserve revisions, proved and probable FD&A costs were a much stronger $19.66 per barrel of oil equivalent. In light of these results, Zargon plans on reducing 2007 capital spending in this area by approximately 35 percent compared to the previous year. Activity will be focused on natural gas targets that may deliver lower initial rates but provide a longer life and more predictable production profile. *Heading into 2007, Zargon is encouraged about the West Central Alberta core area's outlook as scheduled natural gas production tie-ins from recent exploration successes and previously drilled wells should provide four million cubic feet per day of production additions by mid-year.*

GROWTH STRATEGY

In addition to our sustainability objectives for our internally generated capital programs, our business strategy envisions a modest level of growth, on a per trust unit basis, to be provided by corporate and property acquisitions. Additional capital for these acquisition programs can be sourced from the use of funds flow from operations attributable to our exchangeable shares, the use of unutilized bank facilities and/or from accretive equity issuances. Our acquisition efforts will be focused on those opportunities that provide for the replenishment of our feedstock of undeveloped natural gas exploration acreage or our underdeveloped oil exploitation properties. As these acquisitions will not be funded by cash flow, they will be subjected to different investment criteria than our exploration and development programs. More specifically, these acquisitions must provide undeveloped land or underdeveloped oil property resources that can support future exploration, development and exploitation programs that meet our sustainability criteria.

2006 FINANCIAL HIGHLIGHTS

- Revenue decreased by five percent to $154.04 million.
- Funds flow from operations decreased by two percent to $83.52 million.
- Funds flow from operations per diluted trust unit decreased by four percent to $4.34.
- Net earnings increased by 26 percent to $44.50 million.
- Net earnings per diluted trust unit increased by 22 percent to $2.68.

2006 FINANCIAL HIGHLIGHTS (CONT'D)

- Cash distributions decreased by four percent to $35.90 million.
- Cash distributions per trust unit decreased by seven percent to $2.16.
- Consistent with our strategy, this year's distributions represented 50 percent of the year's funds flow from operations on a per diluted trust unit basis (43 percent of the Trust's funds flow from operations).

OUTLOOK

For most of 2006, our industry enjoyed a highly prosperous phase driven by high commodity prices and the resulting high revenues and funds flow from operations, but these conditions also resulted in significant cost pressures due to the related high demand for materials and services. As we enter 2007, the commodity price outlook for crude oil and natural gas has become more subdued and in the short term the combined effects of lower commodity prices and the recently announced proposed changes to the Canadian income trust rules appear to have negatively impacted the Canadian oil and gas trust industry's access to new low-cost capital from debt and equity markets. This change in industry conditions is resulting in improved access to reasonably priced Crown land purchases, farm-in opportunities on competitor's assets and more realistically priced property and corporate acquisitions. With an expanded technical staff to support higher levels of activity and our relatively low debt levels, Zargon is well-positioned in such an environment of reduced competition and improved access to value creation opportunities.

In 2007, Zargon will respond to the changing industry environment of lower cash flows and reduced equity inflows to our industry with a continuing commitment to sustain reserves and production through exploring and developing our undeveloped land holdings and exploiting our oil-in-place resources. In light of the October 31, 2006 announcement regarding the proposed changes to tax rules for income trusts, Zargon will continue to monitor industry developments and the impact of these new rules while enjoying the benefits of the four-year grandfathering period of preferred tax treatment for the existing trusts. Despite this period of change for trusts in general, our organization is well-positioned and committed to executing its business strategy that it has followed over its value-seeking fourteen-year history.

ACKNOWLEDGEMENTS

We are thankful for the commitment, skill and support of our staff as we continue to strive to efficiently execute our oil and gas business in order to enhance the long term value of Zargon. We also extend our gratitude to our Board of Directors for their valuable wisdom, advice and support. Specifically, we would like recognize the passing of H. Earl Joudrie in 2006, one of our former directors who provided us with many years of valuable counsel. He will be deeply missed. Finally, on behalf of all employees and our Board, I want to express our appreciation to our unitholders for their confidence and support for our unwavering commitment to our sustainable trust strategy.

C.H. Hansen
President and Chief Executive Officer
March 13, 2007

DANIEL A. ROULSTON
Executive Vice President, Operations

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HENRY J. BAIRD
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CORE AREAS AND BUSINESS STRATEGIES

NATURAL GAS EXPLORATION AND DEVELOPMENT BUSINESS

Zargon's natural gas exploration and development activities are concentrated in two core areas:

- The Alberta Plains core area consists of generally mature natural gas producing properties and provides the majority of the Trust's natural gas production and reserves. This existing production is predominantly high working interest, operated and produced into Zargon owned production infrastructure. This core area provides both seismically defined Mannville exploration prospects plus shallow natural gas (Viking and Mannville) down-spacing and commingling development projects. On a relative basis, both the capital costs and the resulting reserves per well are relatively small. In 2006, Zargon maintained production volumes and increased reserves in the Alberta Plains core area with a reinvestment of 60 percent of the cash flow generated in this core area.
- The West Central Alberta core area properties are more exploratory in nature and are located in three specific regions where Zargon has accumulated a considerable undeveloped land position. Capital costs for the West Central Alberta exploration wells tend to be much larger than the Alberta Plains wells and in some circumstances the natural gas reserves and production rates can be significant. In 2006, Zargon invested 136 percent of the cash flow generated in this core area drilling exploration prospects in each of the Peace River Arch, Pembina and Highvale properties of this West Central Alberta core area.

In general, both of Zargon's natural gas exploration and development activities are based on geophysical and geological analysis to identify and pursue drilling opportunities on the Trust's substantial inventory of undeveloped lands. These undeveloped lands are predominantly situated in large, concentrated land blocks and for the most part these lands are accessible for all season operations.

OIL EXPLOITATION BUSINESS

Zargon's oil business is built on the exploitation of long-life, shallow-decline oil properties that are characterized by large under-exploited volumes of oil-in-place. Zargon's oil properties are primarily located in the Williston Basin core area of south eastern Saskatchewan, south western Manitoba and immediately across the border in the northern counties of North Dakota. In 2006, Zargon reinvested 52 percent of the cash flow generated in this core area and was able to increase production volumes by six percent. The Trust utilizes reservoir engineering, three-dimensional ("3D") seismic, horizontal

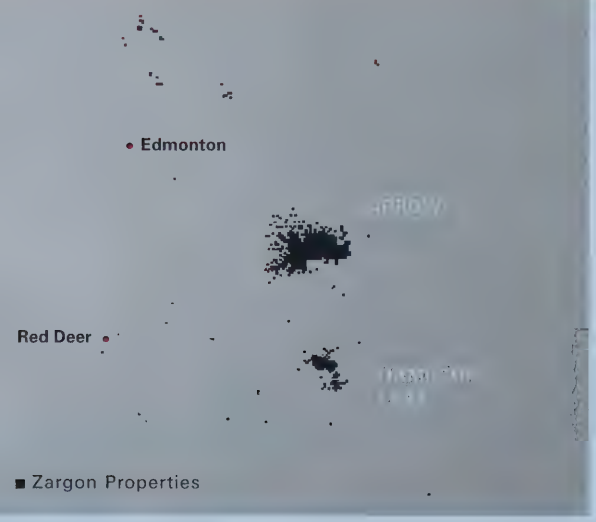
drilling and detailed geological mapping to identify opportunities to increase production and to maximize the ultimate oil recoveries from this large oil-in-place resource base. Frequently, the oil exploitation initiatives include the implementation or modification of waterflood projects.

2006 CORE AREA STATISTICAL SUMMARY

	Alberta Plains	West Central Alberta	Williston Basin	Total
Production (boe/d)	3,736	1,534	3,152	8,422
Production growth/(decline) (percent)	(1)	(3)	6	1
Proved and probable reserves (mboe)[1]	9,818	3,785	13,861	27,464
Annual reserve growth (percent)	2	(6)	6	3
Undeveloped land (thousand net acres)	120.5	202.2	58.6	381.3
Undeveloped land growth (percent)	–	2	21	4
Core area cash flow ($ million)[2]	38.23	13.41	42.55	94.19
Capital program ($ million)	22.95	18.29	22.13	63.37
Drilling program (net wells)	39.5	14.7	22.0	76.2
Three-year FD&A costs ($/boe)[3]	11.90	43.08	10.60	15.98

1. *Proved and probable reserves are trust working interest reserves before royalties (6:1).*
2. *The summation of the 2006 core area cash flows are $94.19 million, which compares to the Trust's 2006 funds flow from operations of $83.52 million. The term "core area cash flow" is defined as petroleum and natural gas revenue for a core area, net of royalties and production expenses. The term "funds flow from operations" is defined in the MD&A section of this report. The difference between the summation of the core area cash flows and the funds flow from operations is comprised of the corporate charges including general and administrative expenses, interest and financing costs, realized risk management gains/losses and corporate taxes.*
3. *The reported proved and probable finding, development and acquisition ("FD&A") costs include an allowance for the change in future capital expenditures. This calculation also includes allowances for prior year reserve revisions and the 2003 reserve definition changes relating to National Instrument 51-101 Standards of Disclosure.*

ALBERTA PLAINS

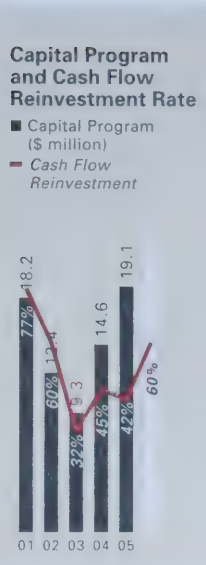


The Alberta Plains core area provides substantial cash flows that are approximately equally allocated to trust distributions and to the reinvestment programs required to maintain stable production volumes and reserves.

The Trust's Alberta Plains core area is located in the east central region of Alberta and is made up predominantly of relatively shallow natural gas producing properties. This core area delivered 70 percent of Zargon's total natural gas production in 2006 and contributes the free cash flow that underpins the Trust's monthly cash distributions. Production volumes have been maintained at a relatively stable level since 2001 through exploration and development drilling programs on the Trust's existing land base. In 2006, the Alberta Plains core area generated $38.23 million of property cash flow, of which $22.95 million was reinvested in the core area to maintain production volumes and reserves.

2007 ALBERTA PLAINS KEY INITIATIVES

- Continue with successful seismically focused Jarrow exploration programs.
- Continue with multi-well development programs at Jarrow and Hamilton Lake focusing on Viking and Mannville down-spacing and commingling development opportunities.
- Develop the Taber oil property through horizontal drilling and waterflood modifications.
- Efficiently deliver a $23 million capital program drilling approximately 32 net wells at the Jarrow, Hamilton Lake and Taber properties.
- Reinvest approximately 50 percent of the core area's cash flow to grow the Alberta Plains production base to approximately 3,950 barrels of oil equivalent per day.
- Seek to acquire additional Alberta Plains properties with an augmented acquisition budget that brings significant undeveloped lands or underdeveloped natural gas properties.



During 2006, the Trust concluded a successful capital program focused on drilling, completions and tie-ins. While providing more than $15.28 million of core area cash flow in excess of capital expenditures, the area's year end proved and probable reserves remained relatively steady, increasing two percent to 9.82 million barrels of oil equivalent. The core area's production volumes were essentially flat with 2006 production volumes declining one percent to 3,736 barrels of oil equivalent per day but with a 2006 exit rate of production of approximately 3,900 barrels of oil equivalent per day, this core area is well positioned to meet its production target for 2007. During a year of higher industry costs, the efficient 2006 Alberta Plains capital programs provided proved and probable reserve additions at a cost of $18.03 per barrel of oil equivalent.

Alberta Plains

	2006	2005	2004	2003	2002
Average Production					
Oil and liquids (bbl/d)	**520**	553	595	640	660
Natural gas (mmcf/d)	**19.29**	19.38	19.02	17.31	17.52
Equivalents (boe/d)	**3,736**	3,783	3,765	3,525	3,580
Total Proved & Probable Reserves[1]					
Oil and liquids (mbbl)	**2,079**	1,962	1,932	1,840	2,065
Natural gas (bcf)	**46.44**	46.00	46.57	44.01	49.74
Equivalents (mboe)	**9,818**	9,625	9,694	9,208	10,355
Undeveloped Lands					
Net acres (thousands)	**120.5**	120.5	146.0	185.4	189.3
Drilling Activities					
Net wells	**39.5**	25.1	21.4	12.8	14.9

1. Proved and probable reserves are trust working interest reserves before royalties (6:1).

Alberta Plains (cont'd)

	2006	2005	2004	2003	2002
Capital Expenditures ($ million)					
Net property and corporate acquisitions/(dispositions)	**0.79**	0.03	0.60	(1.16)	5.20
Undeveloped land, seismic, geological	**3.12**	2.41	3.09	3.04	1.48
Drilling, completion, equipping, facilities	**19.04**	16.63	10.88	7.39	5.68
Total expenditures	**22.95**	19.07	14.57	9.27	12.36
Capital Program Efficiencies					
Finding, development and acquisition costs ($/boe)[2]	**18.03**	14.36	7.56	65.03	15.41

2. The reported proved and probable finding, development and acquisition ("FD&A") costs include an allowance for the change in future capital expenditures. This calculation also includes allowances for prior year reserve revisions and the 2003 reserve definition changes relating to National Instrument 51-101 Standards of Disclosure.

Going forward, Zargon continues to have a large inventory of opportunities that should provide stable Alberta Plains production volumes through 2007. These opportunities include new exploration plus development drilling programs in the following key properties:

JARROW

The Jarrow property continues to be the Trust's most significant producing natural gas property. This property is characterized by high working interests, ownership and operatorship of significant pipeline and gas processing facilities and a large inventory of prospects on a 91 thousand net acre undeveloped land inventory. This undeveloped land inventory is an increase of 11 percent from 2005. This increase is attributable to the freehold leasing program during the year and fewer expiries occurring in 2006 than in 2005. It is anticipated that the Jarrow land inventory will remain relatively unchanged in 2007.

During the year, Zargon drilled 16.9 net (22 gross) wells at Jarrow, resulting in 14.4 net natural gas wells, 0.5 net oil wells and 2.0 net dry holes. The Trust also shot 89 kilometres of two-dimensional ("2D") seismic as part of its ongoing exploration and development programs.

Zargon's strategy for Jarrow has been to sustain net natural gas production levels from this property at approximately 15 million cubic feet per day. This strategy attempts to balance, in a sustainable manner, the efficient loading of the existing infrastructure capacity while capitalizing on a considerable inventory of natural gas prospects. In 2006, the Trust focused on recent down-spacing approvals that allowed further development of the large partially drained Viking, Ostracod, Glauconite and Colony pools located in the two Jarrow Units. In 2007, emphasis will remain on further developing low cost opportunities in the Viking pool, Mannville material balance opportunities and seismically based Mannville exploration through a 19 net well program.

HAMILTON LAKE

Also located in the Alberta Plains core area is the Hamilton Lake property where Zargon produced 2.65 million cubic feet of natural gas per day and 86 barrels of oil and liquids per day in 2006 from the Mannville and Viking formations. The property consists of a mostly contiguous 18 thousand net acre land block that has significant development potential in the lower permeability but extensive first Viking sand formation.

In 2006, Zargon drilled 15.5 net (16 gross) wells at Hamilton Lake resulting in 15.5 net natural gas wells. Similar to the Jarrow property, in 2007 Zargon intends on developing low cost Viking natural gas opportunities with a planned 10 net well program.

TABER

Taber is a medium gravity oil property within the Alberta Plains core area and is an emerging new focus area for Zargon. In 2006, this property produced 316 barrels of oil and liquids per day and 1.0 net horizontal oil well and 1.0 net water injection well were drilled. Based on encouraging results from 2006, Zargon is planning waterflood modifications and a three net horizontal well infill program in 2007 to further develop the potential of this area.

WEST CENTRAL ALBERTA

Zargon's West Central Alberta core area is located north west of Edmonton in central Alberta and is comprised of three natural gas producing regions that provide the Trust with a varied inventory of exploration opportunities. This core area currently delivers approximately 30 percent of Zargon's natural gas production and with exploration success can provide Zargon the opportunity to grow its natural gas production volumes. In 2006, Zargon spent $18.29 million of capital in the West Central Alberta core area, which represented 136 percent of the $13.41 million of property cash flow generated by this area. With these expenditures, Zargon drilled 14.7 net wells in this core area that resulted in 13.7 net natural gas wells and 1.0 net dry hole.

During 2006, the West Central Alberta core area's production declined three percent to 1,534 barrels of oil equivalent per day. Although an active field program was conducted in 2006, tie-ins in this core area were offset by a combination of higher than expected natural declines, scheduled and unscheduled third party gas plant maintenance and weather related delays.

During the year, the West Central Alberta core area's undeveloped acreage increased by two percent to 202 thousand net acres. Due to the impact of approximately 3.8 billion cubic feet of negative reserve revisions coming primarily from the Sturgeon Lake, Highvale, Judy Creek and Progress properties, the core area's proved and probable reserves showed a six percent decline to 3.79 million barrels of oil equivalent. The corresponding 2006 finding and development costs for the core area was $59.19 per barrel of oil equivalent. Excluding the impact of the reserve revisions, the 2006 West Central Alberta drilling program would have delivered a nine percent increase in proved and probable reserves and more acceptable finding and development costs of $19.66 per barrel of oil equivalent.

West Central Alberta

	2006	2005	2004	2003	2002
Average Production					
Oil and liquids (bbl/d)	**168**	209	218	260	234
Natural gas (mmcf/d)	**8.19**	8.25	9.56	7.27	2.31
Equivalents (boe/d)	**1,534**	1,584	1,814	1,472	619
Total Proved & Probable Reserves[1]					
Oil and liquids (mbbl)	**406**	455	499	585	618
Natural gas (bcf)	**20.27**	21.49	22.00	22.19	18.56
Equivalents (mboe)	**3,785**	4,036	4,166	4,283	3,711
Undeveloped Lands					
Net acres (thousands)	**202.2**	197.7	184.9	173.6	109.1
Drilling Activities					
Net wells	**14.7**	14.1	20.6	17.8	12.8
Capital Expenditures ($ million)					
Net property and corporate acquisitions/(dispositions)	**(0.80)**	0.13	0.40	(2.33)	5.25
Undeveloped land, seismic, geological	**2.68**	3.20	4.77	7.50	4.55
Drilling, completion, equipping, facilities	**16.41**	12.44	16.95	10.38	7.12
Total expenditures	**18.29**	15.77	22.12	15.55	16.92
Capital Program Efficiencies					
Finding, development and acquisition costs ($/boe)[2]	**59.19**	38.23	40.95	13.63	12.50

1. Proved and probable reserves are trust working interest reserves before royalties (6:1).

2. The reported proved and probable finding, development and acquisition ("FD&A") costs include an allowance for the change in future capital expenditures. This calculation also includes allowances for prior year reserve revisions and the 2003 reserve definition changes relating to National Instrument 51-101 Standards of Disclosure.

During the first half of 2007, Zargon will tie-in nine (8.6 net) wells into third party facilities which should provide an additional four million cubic feet per day of net production. The gains from these tie-ins should provide a relatively stable level of 2007 production for this core area. Building on specific successful 2006 exploration programs, Zargon will undertake a 2007 refocused exploration program in each of the following key properties:

GREATER HIGHVALE

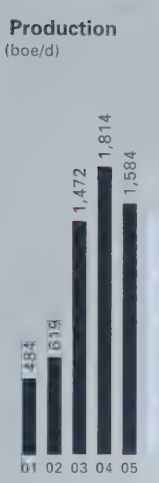
Zargon's 43 thousand net acres of undeveloped land in the Greater Highvale property is centred around a 54 section land block situated on and around Paul First Nation lands located west of Edmonton. Zargon owns and operates natural gas production infrastructure in the area and pursues seismically defined structural and stratigraphic prospects at medium depths. The structural geology lends itself to stacked pay with potential for multiple pay zones.

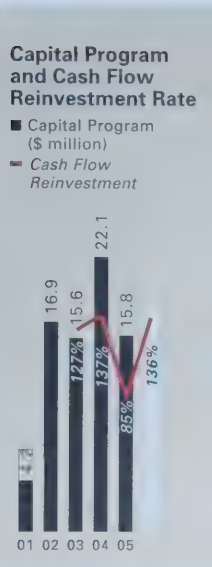
Greater Highvale activities in 2006 included the drilling of 1.6 net natural gas wells. In addition, during the year Zargon shot a 10 kilometre 2D seismic program in the area.

The Greater Highvale property provided 3.45 million cubic feet per day of natural gas and six barrels per day of oil and liquids production to Zargon in 2006. In 2007, three net natural gas exploration wells are planned for the Highvale area.

2007 WEST CENTRAL ALBERTA KEY INITIATIVES

- Tie-in nine (8.6 net) previously drilled natural gas wells adding approximately four million cubic feet per day of new production.
- Continue with selected Peace River Arch exploration programs building on 2006 Bluesky exploration successes. Initiate joint exploration programs or third party farm-outs of deeper or higher risk targets.
- Refocus the Pembina shallow natural gas programs to improve returns and to evaluate coal bed methane concepts.
- Continue with successful seismically focused Highvale exploration programs.
- Efficiently deliver a $12 million capital program drilling approximately 11 net wells at the Highvale, Pembina and Peace River Arch properties.
- With this reduced capital program, offset production declines and maintain West Central Alberta's production levels at 1,600 barrels of oil equivalent per day.





PEMBINA SHALLOW GAS

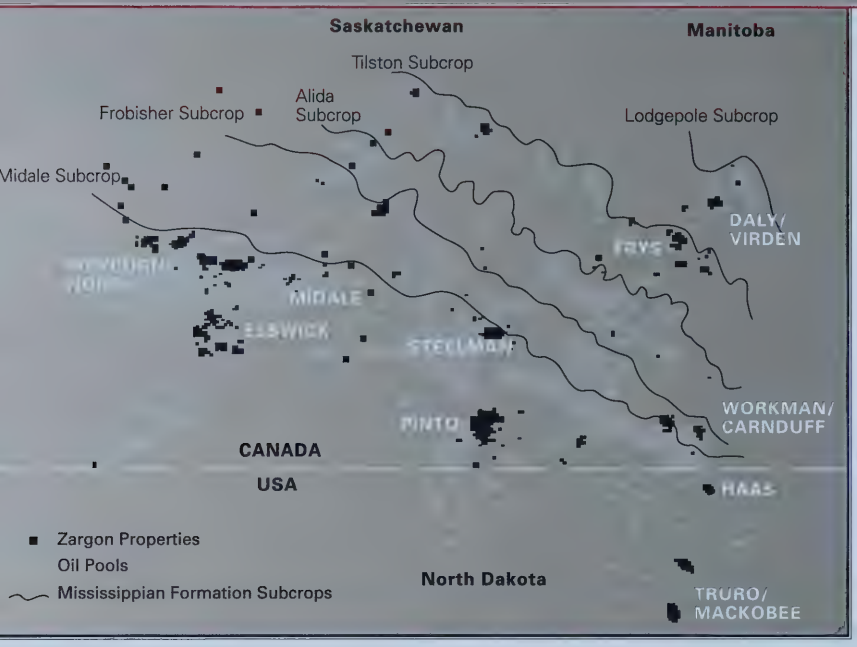
Over the last six years, Zargon has been pursuing shallow under-pressured Scollard and Horseshoe Canyon sands in the Pembina area at depths up to 900 metres. Zargon has an inventory of 65 thousand net acres on this prospect.

In 2006, Zargon drilled 7.5 net natural gas wells in the Pembina area and the property provided 2.44 million cubic feet per day of natural gas and 128 barrels per day of oil and liquids production to Zargon's interest. Zargon is planning a reduced three net well drilling program in 2007.

PEACE RIVER ARCH EXPLORATION

In the Peace River Arch exploration area, Zargon is pursuing multiple zone gas exploration prospects at drilling depths ranging up to 1,800 metres. The Peace River Arch exploration strategy is more "grassroots" than in other areas as the Trust develops prospects, posts land, shoots seismic and drills high graded prospects. Zargon has a 91 thousand net acre undeveloped land inventory that is generally characterized by year round surface access and sweet natural gas multi-zone prospects.

In 2006, the Trust drilled 5.6 net wells in the Peace River Arch area that resulted in 4.6 net natural gas wells and 1.0 net abandonment. Production for the area averaged 2.13 million cubic feet per day of natural gas and 14 barrels per day of oil and liquids. For 2007, Zargon is planning on a refocused five net well drilling program.



The Williston Basin properties are located in relatively close proximity in south east Saskatchewan, south west Manitoba and in the northern counties of the State of North Dakota. The properties produce light and medium gravity oil from carbonate reservoirs at depths up to 1,500 metres. The Williston Basin contributes about 82 percent of the Trust's oil and liquids production, 84 percent of the Trust's proved and probable oil and liquids reserves and provides a long proved and probable reserve life of 12.2 years.

Zargon's Williston Basin producing reservoirs are characterized by moderate permeability and a large remaining oil-in-place. By the nature of the physical characteristics of these reservoirs, the properties demonstrate relatively stable production with shallow annual production declines and accordingly, long reserve life indices.

Through exploitation projects, Zargon attempts to find methods to increase oil recoveries from these reservoirs. Generally, Zargon uses a combination of exploitation techniques including pressure maintenance by water injection, 3D seismic and horizontal drilling to unlock additional oil reserves. Frequently, optimizing pressure support in the oil reservoir by water injection is the first step in the exploitation process. With pressure support established, Zargon seeks to characterize the reservoirs through 3D seismic analysis and interpretation, which is followed by drilling horizontal wells designed to increase recovery and accelerate production.

The following table identifies 20 Williston Basin waterflood exploitation projects that Zargon is currently undertaking:

Williston Basin Oil Exploitation Projects

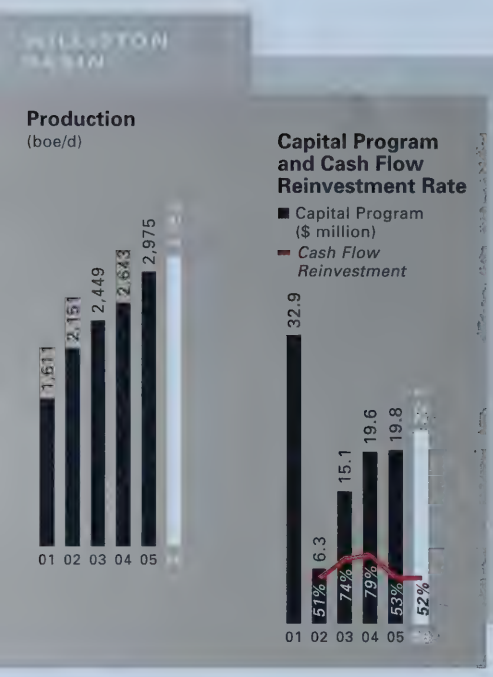
	Waterflood Projects	Zargon Working Interest (percent)	WI[1] Oil-in-Place (mmbbl)	WI Cumulative Production (mmbbl)	WI Recovery To Date (percent)	WI[2] Remaining Reserves (mmbbl)	WI Ultimate Recovery (mmbbl)	Ultimate Recovery (percent)
North Dakota								
Haas	1	98	53.6	10.4	19	3.6	14.0	26
Truro/Mackobee	2	100	22.0	2.8	13	1.3	4.1	19
Manitoba								
Daly/Virden	2	100	27.6	3.1	11	1.2	4.3	16
Saskatchewan								
Elswick	3	95	12.5	1.3	10	0.9	2.2	18
Frys	2	100	11.0	1.3	12	0.5	1.8	16
Midale	1	97	7.7	1.0	13	0.2	1.2	16
Pinto	2	100	8.4	0.8	10	0.7	1.5	18
Steelman	2	89	10.5	1.5	14	0.8	2.3	22
Weyburn North	3	76	20.0	2.9	15	1.1	4.0	20
Workman/Carnduff	2	53	8.2	1.3	16	0.5	1.8	22
Total	20		181.5	26.4	15	10.8	37.2	20

1. As estimated by Zargon's management.

2. Represents 2006 year end remaining proved and probable reserves as estimated by McDaniel & Associates.

These 20 waterflood projects, which represent 78 percent of Zargon's Williston Basin reserves, are in various stages of implementation and are estimated to contain 182 million barrels of oil-in-place attributed to Zargon's working interests. Based on the year end 2006 McDaniel & Associates ("McDaniel") proved and probable reserve assignment, these properties are predicted to recover an average of 20 percent of their original oil-in-place. Going forward, Zargon will continue to reinvest considerable time and capital to improve these ultimate recovery factors through a multi-year program of exploitation drilling and waterflood modifications.

In 2006, Zargon drilled 10.7 net horizontal wells and 11.3 net vertical wells in the Williston Basin resulting in 21.0 net oil wells and 1.0 net water injector well. The Trust also shot a 32 kilometre 2D seismic program at Pinto, Saskatchewan and a four square kilometre 3D seismic program at Manor, Saskatchewan. In addition to the exploitation and development drilling activities, the 2006 capital program included 5.0 net vertical wells at Frys East and Pinto that explored for Torquay and Frobisher targets.



2007 WILLISTON BASIN KEY INITIATIVES

- Continue with successful exploitation and development programs on our significant Williston Basin oil-in-place resource base through ongoing programs of 3D seismic, waterflood modifications and exploitation drilling.
- Continue with selected Torquay and Frobisher exploration programs at the Greater Frys and Pinto properties.
- Efficiently deliver a $20 million capital program drilling approximately 17 net wells at the Frys East, Elswick, Pinto, Steelman and Weyburn, Saskatchewan plus the Haas, Mackobee Coulee and Truro, North Dakota properties.
- Offset production declines and increase Williston Basin production levels to 3,200 barrels of oil equivalent per day.
- Seek to acquire additional Williston Basin oil properties with an augmented acquisition budget that brings properties with significant oil exploitation potential.

In 2006, the Williston Basin area generated $42.55 million of property cash flow of which $22.13 million, or 52 percent, was reinvested in the core area. Through the reinvestment of just over half of the Williston Basin cash flow, Zargon was able to realize a six percent increase in Williston Basin production volumes from 2,975 barrels of oil equivalent per day in 2005 to 3,152 barrels of oil equivalent per day in 2006. This capital program also delivered a six percent increase in the year end proved and probable reserves to 13.86 million barrels of oil equivalent. The efficient 2006 Williston Basin capital programs provided proved and probable reserve additions at $15.99 per barrel of oil equivalent with almost half of the incremental reserves coming from technical revisions related to ongoing waterflood programs. In particular, the 2006 drilling program provided significant wells at the Steelman, Elswick, Pinto and Weyburn properties, which will be followed up with further development in 2007.

Going forward, Zargon has identified numerous exploitation opportunities that should provide stable or growing core area production volumes for many years to come.

Zargon owns a significant inventory of exploitable Williston Basin properties producing from Mississippian carbonate reservoirs characterized by shallow production declines and a large oil-in-place.

Williston Basin

	2006	2005	2004	2003	2002
Average Production					
Oil and liquids (bbl/d)	**3,117**	2,935	2,603	2,387	2,074
Natural gas (mmcf/d)	**0.22**	0.24	0.26	0.37	0.46
Equivalents (boe/d)	**3,152**	2,975	2,643	2,449	2,151
Total Proved & Probable Reserves[1]					
Oil and liquids (mbbl)	**13,452**	12,942	11,930	11,105	9,761
Natural gas (bcf)	**2.45**	1.01	0.98	0.86	0.93
Equivalents (mboe)	**13,861**	13,110	12,093	11,248	9,916
Undeveloped Lands					
Net acres (thousands)	**58.6**	48.6	45.1	39.4	32.9
Drilling Activities					
Net wells	**22.0**	14.3	7.5	8.0	3.9
Capital Expenditures ($ million)					
Net property and corporate acquisitions/(dispositions)	**(3.14)**	2.26	10.82	6.10	1.20
Undeveloped land, seismic, geological	**2.80**	1.51	1.24	2.13	0.90
Drilling, completion, equipping, facilities	**22.47**	16.07	7.52	6.86	4.17
Total expenditures	**22.13**	19.84	19.58	15.09	6.27
Capital Program Efficiencies					
Finding, development and acquisition costs ($/boe)[2]	**15.99**	8.78	11.76	6.66	5.21

1. Proved and probable reserves are trust working interest reserves before royalties (6:1).

2. The reported proved and probable finding, development and acquisition ("FD&A") costs include an allowance for the change in future capital expenditures. This calculation also includes allowances for prior year reserve revisions and the 2003 reserve definition changes relating to National Instrument 51-101 Standards of Disclosure.

ACTIVITY REVIEW

HIGHLIGHTS

Zargon had an active and successful year in 2006, drilling a record 76.2 net wells, a 42 percent increase over the prior year. In addition to supporting Zargon's $2.16 per trust unit of distributions, this drilling program delivered a one percent gain in production and a three percent increase in proved and probable reserves.

	2006	2005	Percent Change
Undeveloped land (thousand net acres)	**381**	367	4
Wells drilled, net	**76.2**	53.5	42
Total production (boe/d)	**8,422**	8,342	1
Year end proved and probable reserves (mmboe)	**27.46**	26.77	3

LAND AND SEISMIC

In 2006, Zargon spent $5.25 million on replenishing and maintaining its undeveloped land base. This total was 44 percent higher than the $3.65 million spent in 2005. During the year, Zargon purchased 42 thousand net acres, primarily consisting of natural gas prospective Alberta Crown lands for a total cost of $3.70 million or $88 per acre. Previously, Zargon had acquired 31 thousand net acres in 2005 and 39 thousand net acres in 2004 at average costs of $113 and $93 per acre, respectively.

Zargon's undeveloped land inventory increased four percent in 2006 to 381 thousand net acres. This increase resulted from the combination of an increased Crown land acquisitions program offset by a reduced level of expiries compared to 2005. In 2007, Zargon anticipates undeveloped land expiries of approximately 80 thousand net acres, and of these land expiries a significant percentage will be replenished by Crown and freehold land acquisitions.

The independent firm of Seaton-Jordan & Associates Ltd. ("Seaton-Jordan") has valued Zargon's undeveloped land holdings as of December 31, 2006 at $43.55 million, a four percent increase in value over last year's $41.72 million appraisal. This analysis reflects an average value of $114 per acre, unchanged from the per acre average in 2005.

As part of its continuing exploration effort, Zargon shot 142 kilometres of 2D seismic and 8.1 square kilometres of 3D seismic in 2006. Approximately 89 kilometres of the 2D seismic was shot at the Jarrow property as Zargon continued to assess its considerable inventory of land and natural gas prospects in this productive area. Total geological and geophysical costs in 2006 were $3.34 million, which is four percent lower than the prior year's geological and geophysical expenditures of $3.47 million primarily due to a reduced seismic program in the West Central Alberta core area.

DRILLING, COMPLETIONS AND WORKOVERS

Zargon drilled a record 76.2 net wells in 2006, a 42 percent increase in drilling activity from 2005 and a 54 percent increase from 2004. The 2006 drilling program resulted in 22.5 net oil wells, 47.7 net natural gas wells, 2.0 net water injectors and 4.0 net dry holes. Zargon's success ratio was 95 percent in the 2006 drilling program, an increase of two percent from the 93 percent success ratio in 2005.

Drilling Activity

(Number of Wells)	2006		2005		2004	
	Gross	**Net**	Gross	Net	Gross	Net
Oil	**26**	**22.5**	15	13.5	7	5.7
Natural gas	**57**	**47.7**	40	35.3	44	35.4
Water injector	**2**	**2.0**	1	0.9	1	0.8
Dry	**4**	**4.0**	4	3.8	8	7.6
Total	**89**	**76.2**	60	53.5	60	49.5
Exploratory	**30**	**28.8**	25	23.0	29	25.9
Development	**59**	**47.4**	35	30.5	31	23.6
Total	**89**	**76.2**	60	53.5	60	49.5
West Central Alberta	**16**	**14.7**	16	14.1	23	20.6
Alberta Plains	**48**	**39.5**	28	25.1	28	21.4
Williston Basin	**25**	**22.0**	16	14.3	9	7.5
Total	**89**	**76.2**	60	53.5	60	49.5
Average Zargon Working Interest		**86%**		89%		83%

During 2006, Zargon operated the drilling of 79 gross wells with an average working interest of 93 percent. Zargon's minor participation in an additional 10 non-operated wells brought Zargon's average working interest to 86 percent. Similar to recent years, the drilling program was primarily weighted to Alberta natural gas targets with 71 percent of the net wells drilled in the Alberta Plains and West Central Alberta natural gas core areas compared to 73 percent in 2005. In 2007, Zargon is planning to drill 60 net wells with about two thirds of these focused on natural gas exploration and development in the Alberta Plains and West Central Alberta core areas and the remaining wells focused on oil exploitation primarily in the Williston Basin.

In 2006, expenditures for drilling, completion and workovers totalled $41.80 million, a 25 percent increase from the $33.36 million spent in 2005. Drilling related expenditures were sharply higher due primarily to Zargon's increased activity levels and the industry-wide high cost environment experienced in 2006.

(net wells)

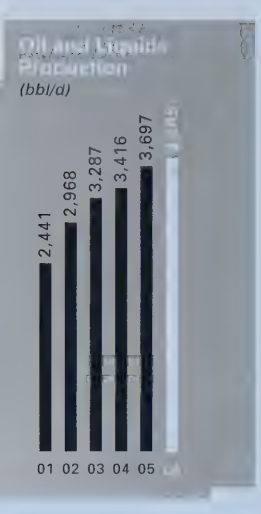
PRODUCTION EQUIPMENT A[illegible]

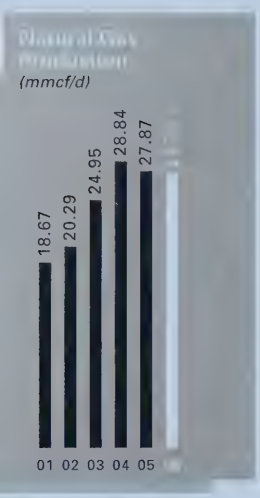
In 2006, Zargon spent $16.12 million, a 37 percent increase over the prior year's level, on production equipment and facilities, which included gas plant expansions, oil battery modifications and the construction of approximately 46 net kilometres of pipelines. Approximately 38 percent of these costs were incurred in Alberta Plains, 32 percent in Williston Basin and 30 percent in West Central Alberta core areas.

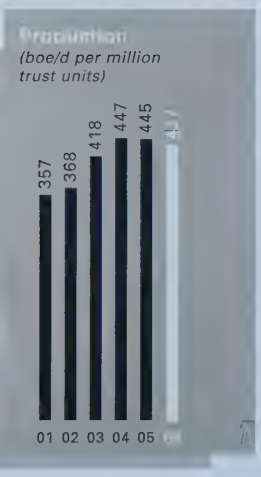
(boe/d)

PROPERTY DISPOSITIONS

Zargon's net property dispositions totalled $3.14 million in 2006, compared to $2.42 million of net property and corporate acquisitions completed in 2005. During 2006, the dispositions related primarily to the $3.70 million sale of two small higher operating cost, non-core oil properties in the Williston Basin core area having a combined 60 barrels per day of oil production. Essentially all of the 2005 net acquisitions related to the purchase of oil properties in the Saskatchewan area of the Williston Basin.







PRODUCTION

Natural gas sales volumes decreased one percent in 2006 to average 27.70 million cubic feet per day, compared to 27.87 million cubic feet per day in 2005 (2004 – 28.84 million cubic feet per day). The decrease in natural gas production was primarily due to unanticipated natural gas production declines from certain wells in the West Central Alberta core area. Crude oil and natural gas liquid sales volumes increased three percent in 2006 to 3,805 barrels per day, compared to 3,697 barrels per day in 2005 (2004 – 3,416 barrels per day). These production gains resulted from oil exploitation drilling programs in the Williston Basin.

Zargon's 2006 average daily production increased one percent to 8,422 barrels of oil equivalent per day compared to 8,342 barrels of oil equivalent per day in 2005 (2004 – 8,222 barrels of oil equivalent per day). On a production per total trust unit basis, Zargon produced 437 barrels of oil equivalent per day per million units in 2006, down two percent from the 2005 level. During the year, natural gas production represented 55 percent of total volumes, relatively unchanged from a 56 percent weighting in 2005.

RESERVES

Formal disclosure of oil, liquids and natural gas reserves as required by National Instrument 51-101 Standards of Disclosure ("NI 51-101") will be included in the Trust's Annual Information Form for the year ended December 31, 2006 that will be filed on SEDAR.

Since 1993, the independent engineering firm of McDaniel & Associates Consultants Ltd. ("McDaniel") has evaluated 100 percent of Zargon's reserves. Commencing with the 2003 year end report, Zargon's reserve estimates have been calculated in accordance with National Instrument 51-101 ("NI 51-101"). Under NI 51-101, proved reserve estimates are defined as having a 90 percent probability that actual reserves recovered over time will equal or exceed proved reserve estimates. Probable reserves are defined under NI 51-101 so that there are equal (50 percent) probabilities that the actual reserves to be recovered will be less than, or greater than, the proved and probable reserves estimate.

In a report dated February 21, 2007, McDaniel assigned the following reserve estimates based on forecast prices and costs as of December 31, 2006:

Trust Reserves [1]

At December 31, 2006	Oil and Liquids (mmbbl)	Natural Gas (bcf)	Equivalents [2] (mmboe)
Proved producing	11.01	32.22	16.38
Proved non-producing	0.22	11.41	2.12
Proved undeveloped	0.29	1.52	0.55
Total proved	**11.52**	**45.15**	**19.05**
Probable additional	4.41	24.00	8.41
Total proved and probable	**15.93**	**69.15**	**27.46**
Proved reserve life index, years	8.3	4.5	6.2
Proved and probable reserve life index, years	11.5	6.9	9.0

1. *Trust working interest reserves before royalties, boe (6:1).*
2. *Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

In McDaniel's report, proved producing reserves represented 86 percent of Zargon's total proved reserves while total proved reserves accounted for 69 percent of proved and probable reserves. These percentages are relatively unchanged from the respective 88 and 72 percentages reported

in the 2005 year end report. Zargon's proved non-producing reserves are comprised primarily of natural gas reserves from recently drilled wells at the Alberta Plains core area properties of Jarrow and Hamilton Lake and the West Central Alberta core area properties of Progress, Pembina and Greater Highvale. McDaniel forecasts $14.11 million of net future (forecast prices) capital costs to deliver the total proved reserve estimate. Zargon's probable reserves generally reflect incremental waterflood recoveries on producing oil properties and improved gas recoveries for currently producing natural gas wells. McDaniel forecasts $21.63 million of net future (forecast prices) capital costs to deliver the total proved and probable reserve estimate.

Based on 2006 year end reserves and Zargon's 2006 fourth quarter production rates of 3,789 barrels of oil and liquids per day and 27.46 million cubic feet of natural gas per day, Zargon's proved reserve life index is 8.3 years for oil and liquids, 4.5 years for natural gas and 6.2 years on an oil equivalent basis. The corresponding proved and probable oil and liquids, natural gas and oil equivalent reserve life indices are 11.5, 6.9 and 9.0 years, respectively. The relatively high oil and liquids reserve life reflects Zargon's portfolio of long-life shallow-decline Williston Basin waterflood projects.

RESERVE RECONCILIATION

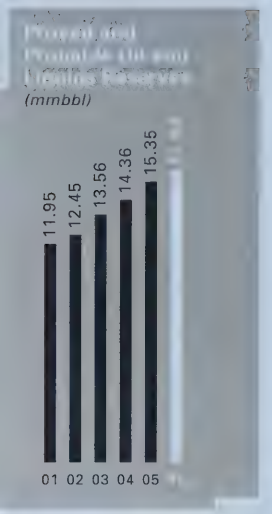
A reconciliation of the 2006 year end reserve assignments with the reserves reported in the 2005 year end report is presented below:

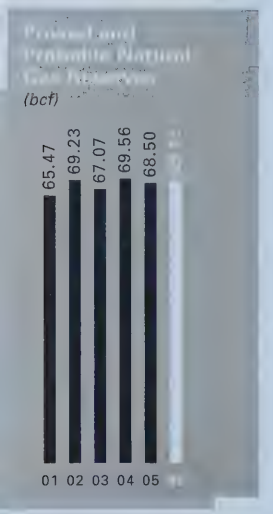
Reserve Reconciliation

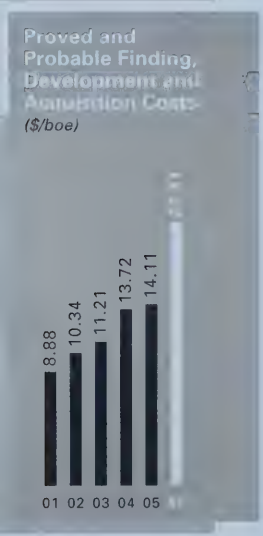
	Oil and Liquids (mmbbl)			Natural Gas (bcf)			Equivalents (mmboe)		
	Proved	Probable	Proved & Prob.	Proved	Probable	Proved & Prob.	Proved	Probable	Proved & Prob
December 31, 2005	11.49	3.86	15.35	46.52	21.98	68.50	19.24	7.53	26.77
Discoveries and extensions	0.91	0.80	1.71	10.06	5.38	15.44	2.59	1.70	4.29
Revisions	0.58	(0.22)	0.36	(1.32)	(3.36)	(4.68)	0.36	(0.79)	(0.43)
Acquisitions and dispositions	(0.07)	(0.03)	(0.10)	–	–	–	(0.07)	(0.03)	(0.10)
Production	(1.39)	–	(1.39)	(10.11)	–	(10.11)	(3.07)	–	(3.07)
December 31, 2006	11.52	4.41	15.93	45.15	24.00	69.15	19.05	8.41	27.46

Proved reserves at December 31, 2006 decreased one percent from the prior year. Proved 2006 reserve additions were 2.88 million barrels of oil equivalent (after revisions) or 2.52 million barrels of oil equivalent (before revisions). Positive technical proved reserve revisions were 0.36 million barrels of oil equivalent, which equated to two percent of the 2006 proved reserves opening balance. Positive revisions attributed to performance-related adjustments to waterflood oil properties in the Williston Basin were offset by negative natural gas revisions due to the watering out of wells located at the Sturgeon Lake, Highvale, Judy Creek and Progress properties in the West Central Alberta core area.

On a proved and probable basis, Zargon increased its reserves by three percent in 2006, with the addition of 3.76 million barrels of oil equivalent (after revisions) or 4.19 million barrels of oil equivalent (before revisions), thereby replacing annual production by a factor of 122 percent (136 percent before revisions). Field capital exploration and development programs provided 4.29 million barrels of oil equivalent of new additions, while dispositions, primarily related to the Fletewode property in Southeast Saskatchewan, totalled 0.10 million barrels of oil equivalent. Negative technical reserve revisions were 0.43 million barrels of oil equivalent which equated to two percent of the 2006 proved and probable reserves opening balance. The majority of the negative technical revisions on a probable basis were due to negative natural gas revisions at the Highvale, Judy Creek and Progress properties of the West Central Alberta core area and the







Hamilton Lake and Jarrow properties of the Alberta Plains core area. Included in the 2006 capital expenditure program was $8.59 million for undeveloped land, geological and geophysical costs that should provide for future reserves additions in subsequent years.

FINDING, DEVELOPMENT AND ACQUISITION COSTS

For 2006, Zargon's proved and probable finding, development and acquisition ("FD&A") costs, taking into account reserve revisions and changes in estimated future development capital during the period, were $20.44 per barrel of oil equivalent. For the purposes of this calculation, the $63.37 million of 2006 net capital additions were combined with an increase in estimated future development capital for proved and probable reserves of $13.48 million ($21.63 million at December 31, 2006 compared to $8.15 million at December 31, 2005). If the change in future development costs is excluded, the 2006 proved and probable FD&A costs, taking into account reserve revisions, were $16.85 per barrel of oil equivalent.

Proved and Probable Finding, Development and Acquisition Costs

	2006	2005	2004
Total net capital expenditures ($ million)	**63.37**	54.68	56.27
Total net capital expenditures plus change in forecast future development costs ($ million)	**76.85**	54.46	57.88
Proved and probable reserves (mmboe)			
Open	**26.77**	25.95	24.74
Discoveries and extensions	**4.29**	3.76	2.97
Acquisitions and dispositions	**(0.10)**	0.12	0.95
Revisions	**(0.43)**	(0.02)	0.30
Production	**(3.07)**	(3.04)	(3.01)
Close	**27.46**	26.77	25.95
Proved and probable FD&A costs ($/boe)[1]	**20.44**	14.11	13.72
Proved and probable three-year FD&A costs ($/boe)[1]	**15.98**	13.09	11.89

1. Amounts are calculated including the change in future development costs.

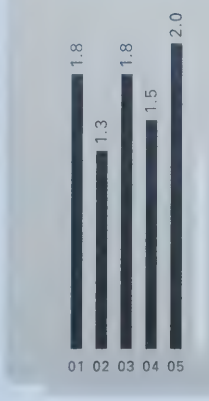
Zargon experienced significantly higher FD&A costs in 2006 due to the combination of the increased costs for essentially all field activities and the effect of negative proved and probable West Central core area natural gas reserve revisions of 3.80 billion cubic feet coming from premature water encroachment in certain Highvale and Peace River Arch wells.

In 2006, Zargon's net property dispositions were $3.14 million. If the impact of the 2006 net dispositions is excluded, Zargon's proved and probable finding and development ("F&D") costs would have been $20.72 per barrel of oil equivalent (2005 – $13.91 per barrel of oil equivalent).

Capital Program Performance

	2006	2005	2004	Three-Year Average (2004-2006)
Trust funds flow from operations ($/boe)[1]	**27.17**	27.91	21.18	25.44
Total Capital Program (excluding future development costs)				
Proved and probable FD&A costs ($/boe)[2]	**16.85**	14.17	13.33	14.72
Trust recycle ratio[3]	**1.61**	1.97	1.59	1.73
Total Capital Program (including future development costs)				
Proved and probable FD&A costs ($/boe)[2]	**20.44**	14.11	13.72	15.98
Trust recycle ratio[3]	**1.33**	1.98	1.54	1.59
Capital Program (including future development costs) **Exclusive of Net Property Acquisitions/Dispositions and Corporate Acquisitions**				
Proved and probable F&D costs ($/boe)[2]	**20.72**	13.91	14.09	16.38
Trust recycle ratio[3]	**1.31**	2.01	1.50	1.55
Production Addition Costs				
Production addition costs ($ thousand/boe/d)[4]	**40.36**	35.30	37.63	37.76
Production addition costs–exclusive of net property acquisitions/dispositions and corporate acquisitions ($ thousand/boe/d)[4]	**42.62**	33.50	29.37	35.16

1. *Trust funds flow from operations including allowances for current taxes, interest and financing charges and general and administrative expenses on a barrel of oil equivalent production basis (6:1).*
2. *FD&A and F&D costs taking into account reserve revisions during the year on a barrel of oil equivalent basis (6:1).*
3. *Trust recycle ratio is defined as the Trust funds flow from operations per barrel of oil equivalent divided by proved and probable finding, development and acquisition costs per barrel of oil equivalent. In the case of amounts for the capital program exclusive of net acquisitions/dispositions and corporate acquisitions, the trust funds flow per barrel of oil equivalent is divided by proved and probable finding and development costs.*
4. *The production addition costs for the total capital program are calculated by dividing the year's net capital expenditures by the year's actual change in production rate plus the year's estimated naturally occurring decline in production. This production decline is estimated as the year end proved producing (forecast case) depletion rate (the inverse of the reserve life index) based on fourth quarter production rates. The production addition costs for the capital program exclusive of net acquisitions/dispositions and corporate acquisitions are calculated on a similar basis except total capital, reserves and production are adjusted for the amounts related to net acquisitions/dispositions and corporate acquisitions.*



NET ASSET VALUE

Zargon's oil, natural gas liquids and natural gas reserves were evaluated using McDaniel product price forecasts effective January 1, 2007, prior to provisions for income taxes, interest, debt service charges and general and administrative expenses. It should not be assumed that the following discounted future net property cash flows estimated by McDaniel represent the fair market value of the reserves:

Before Tax Present Value of Future Net Revenue

(Forecast Price Case)

	Discount Factor			
($ million)	0%	5%	10%	15%
Proved producing	433.2	341.6	284.7	246.4
Proved non-producing	54.2	45.8	39.7	35.1
Proved undeveloped	11.6	9.0	7.1	5.6
Total proved	**499.0**	**396.4**	**331.5**	**287.1**
Probable	261.6	164.9	117.3	89.8
Total proved and probable	**760.6**	**561.3**	**448.8**	**376.9**

Before Tax Present Value of Future Net Revenue

(Constant Price Case)

	Discount Factor			
($ million)	0%	5%	10%	15%
Proved producing	406.2	316.7	262.4	226.0
Proved non-producing	41.0	34.8	30.3	26.8
Proved undeveloped	9.9	7.6	5.9	4.6
Total proved	**457.1**	**359.1**	**298.6**	**257.4**
Probable	213.6	135.4	97.0	74.7
Total proved and probable	**670.7**	**494.5**	**395.6**	**332.1**

The above discounted future net property cash flows are based on the McDaniel price assumptions that are contained in the following table:

McDaniel Report Pricing Assumptions

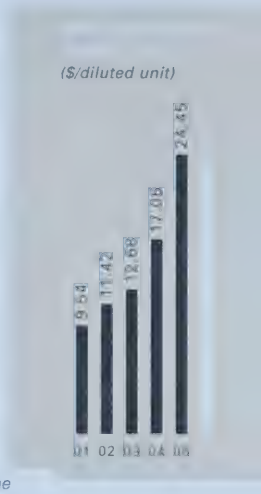
(Forecast and Constant Price Cases)

	WTI Crude Oil ($US/bbl)	Edmonton Par Price ($Cdn/bbl)	Cromer Medium ($Cdn/bbl)	AECO Gas Price ($Cdn/gj)	Exchange Rate ($US/$Cdn)	Inflation Rate (percent)
Forecast Prices						
2007	62.50	70.80	62.20	6.85	0.87	2.0
2008	61.20	69.30	60.90	7.05	0.87	2.0
2009	59.80	67.70	59.40	7.40	0.87	2.0
2010	58.40	66.10	58.00	7.50	0.87	2.0
2011	56.80	64.20	56.40	7.70	0.87	2.0
2012	58.00	65.60	57.60	7.90	0.87	2.0
Thereafter:	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	0.87	2.0
Constant Prices						
2006 year end	61.05	67.06	58.96	5.62	0.87	–

The following net asset value table shows what is customarily referred to as a "produce-out" net asset value calculation under which the current value of Zargon's reserves would be produced at McDaniel forecast future prices and costs. The value is a snapshot in time as of December 31, 2006 and is based on various assumptions including commodity prices and foreign exchange rates that vary over time. In this analysis, the present value of the proved and probable reserves is calculated at a before tax 10 percent discount rate, and the value assigned to the undeveloped land was provided by the independent firm of Seaton-Jordan & Associates Ltd.

Net Asset Value

As at December 31 ($ million)	2006	2005	2004
Proved and probable reserves (PVBT 10%)[1][2]	**448.8**	451.4	308.2
Undeveloped land[3]	**43.6**	41.7	32.2
Working capital (excluding unrealized risk management assets and liabilities)	**(9.8)**	(17.1)	(9.1)
Bank debt	**(30.0)**	(10.3)	(14.2)
Proceeds from the exercise of all trust unit rights	**31.8**	20.9	10.3
Net asset value (including trust unit rights dilution)	**484.4**	486.6	327.4
Net asset value per unit			
Total ($/unit)	**23.30**	24.53	17.04
With full dilution ($/unit)[4]	**23.48**	24.45	17.06



1. *McDaniel's estimate of future before tax cash flow discounted at PV 10 percent.*
2. *PVBT represents present value before taxes.*
3. *Seaton-Jordan year end estimates.*
4. *Full dilution of units represents the year end units outstanding plus the presumed exercise of all trust unit rights and the conversion of exchangeable shares converted at the exchange ratio at the end of the year. At December 31, 2006, Zargon had 16.789 million trust units, 2.207 million exchangeable shares outstanding and 1.208 million trust unit incentive rights issued and outstanding. Assuming conversion of exchangeable shares at the effective exchange ratio at year end of 1.19403 and the exercise of all trust unit incentive rights, there would be 20.632 million trust units outstanding at this date.*

If the net asset value calculation is adjusted to assume that the commodity prices received at year end 2006 (Edmonton light crude oil at $67.06 Cdn per barrel and Alberta AECO average natural gas at $5.62 Cdn per gj) will remain constant throughout the future (McDaniel constant price case), the equivalent analysis calculates a 10 percent present value before tax ("PVBT") net asset value of $20.90 per fully diluted unit.

TRUST SUSTAINABILITY

With the conversion during 2004 to a trust, Zargon's objectives are to sustain distributions, production and reserves on a per unit basis after paying out approximately 50 percent of funds flow attributable to unitholders.

The following is a summary of the key metrics that Zargon monitors as it works towards meeting its sustainability objectives:

Key Sustainability Metrics

	2006	2005	Percent Change
Cash distributions ($/trust unit)	**2.16**	2.32	(7)
Funds flow from operations ($/unit diluted)	**4.34**	4.51	(4)
Trust payout ratio (percent)	**50**	51	(2)
Average production (boe/d per million trust units)	**437**	445	(2)
Proved and probable reserves (boe/total unit)	**1.41**	1.41	–
Funds flow from operations ($/boe)	**27.17**	27.91	(3)
Proved and probable FD&A costs ($/boe)	**20.44**	14.11	45
Trust recycle ratio	**1.33**	1.98	(33)
Production addition costs ($ thousand/boe/d)[1]	**40.4**	35.3	14

1. The production addition costs for the capital program are calculated by dividing the year's net capital expenditures by the year's actual change in production rate plus the year's estimated naturally occurring decline in production. This production decline is estimated as the year end proved producing (forecast case) depletion rate (the inverse of the reserve life index) based on fourth quarter production rates.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") is a review of Zargon Energy Trust's 2006 financial results and should be read in conjunction with the audited consolidated financial statements and related notes for the years ended December 31, 2006 and 2005. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). All amounts are in Canadian dollars unless otherwise noted. All references to "Zargon" or the "Trust" refer to Zargon Energy Trust and all references to the "Company" refer to Zargon Oil & Gas Ltd.

In the MD&A, reserves and production are commonly stated in barrels of oil equivalent (boe) on the basis that six thousand cubic feet of natural gas is equivalent to one barrel of oil (boe). Boes may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalent conversion method primarily applicable to the burner tip and does not represent a value equivalent at the wellhead.

The following are descriptions of non-GAAP measures used in this MD&A:

- *The MD&A contains the term "funds flow from operations" ("funds flow"), which should not be considered an alternative to, or more meaningful than, "cash flow from operating activities" as determined in accordance with Canadian GAAP as an indicator of the Trust's financial performance. This term does not have any standardized meaning as prescribed by GAAP and therefore, the Trust's determination of funds flow from operations may not be comparable to that reported by other trusts. The reconciliation between net earnings and funds flow from operations can be found in the consolidated statements of cash flows in the consolidated financial statements. The Trust evaluates its performance based on net earnings and funds flow from operations. The Trust considers funds flow from operations to be a key measure as it demonstrates the Trust's ability to generate the cash necessary to pay distributions, repay debt and to fund future capital investment. It is also used by research analysts to value and compare oil and gas trusts, and it is frequently included in published research when providing investment recommendations. Funds flow from operations per unit is calculated using the diluted weighted average number of units for the period.*
- *Payout ratio equals distributions as a percentage of funds flow for the period. Payout ratio is a useful measure used by management to analyze the Trust's efficiency and sustainability.*
- *The Trust also uses the term "debt net of working capital". Debt net of working capital as presented does not have any standardized meaning prescribed by Canadian GAAP and may not be comparable with the calculation of similar measures for other entities. Debt net of working capital as used by the Trust is calculated as bank debt and any working capital deficit excluding the current portion of unrealized risk management assets and liabilities.*
- *Operating netbacks equal total petroleum and natural gas revenue per boe adjusted for realized risk management gains and/or losses per boe, royalties per boe and production costs per boe. Operating netbacks are a useful measure to compare the Trust's operations with those of its peers.*
- *Funds flow netbacks per boe are calculated as operating netbacks less general and administrative expenses per boe, interest and financing charges per boe, and capital and current income taxes per boe. Funds flow netbacks are a useful measure to compare the Trust's operations with those of its peers.*

References to "production volumes" or "production" in this MD&A refer to sales volumes.

Forward-Looking Statements: This document contains statements that are forward-looking, such as those relating to results of operations and financial condition, capital spending, financing sources, commodity prices, costs of production and the magnitude of oil and natural gas reserves. By their nature, forward-looking statements are subject to numerous risks and uncertainties that could significantly affect anticipated results in the future and, accordingly, actual results may differ materially from those predicted. The forward-looking statements contained in this MD&A are as of March 12, 2007 and are subject to change after this date. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Zargon disclaims, except as required by law, any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

This MD&A has been prepared as of March 12, 2007.

2006 HIGHLIGHTS

The combination of high crude oil prices and stable production volumes enabled Zargon to achieve strong revenues and funds flow from operations in 2006, showing a slight decline of five percent and two percent, respectively, over the record-setting 2005 prior year results. The annual revenue decline came from a combination of factors, including a 19 percent decrease in natural gas prices received and a one percent decline in natural gas production. Both were substantially offset by an increase of oil and liquids prices received of seven percent and a three percent increase in oil and liquids production. Net earnings for the year were $44.50 million, a 26 percent increase from 2005. Earnings for 2006 were primarily supported by near record funds flow from operations of $83.52 million, a decrease of $1.45 million from 2005, and were further supported by unrealized risk management gains and a future income tax recovery.

Net capital expenditures for 2006 totalled $63.37 million with $66.51 million allocated to field-related activities and $3.14 million to net property disposals. Compared to the prior year, the 2006 capital program showed a 16 percent increase in overall net expenditures and a 27 percent increase in field-related expenditures. For the year ended December 31, 2006, Zargon spent $5.25 million to maintain an undeveloped land base of 381 thousand net acres (2005 – 367 thousand net acres); shot or acquired seismic at a cost of $3.34 million; drilled, equipped and tied-in wells for $57.92 million and generated net property dispositions of $3.14 million. The net property dispositions related primarily to the disposal of two non-core higher operating cost oil properties in the Williston Basin core area. No corporate acquisitions occurred in 2006. Cash distributions to unitholders totalled $35.90 million during the year (2005 – $37.44 million). All of these activities were funded by the funds flow received throughout the year plus an increase in debt net of working capital (excluding the unrealized risk management assets and liabilities) of $12.34 million.

Financial Highlights

($ million, except per unit amounts)	**2006**	2005	2004
Petroleum and natural gas revenue	**154.04**	162.72	123.97
Funds flow from operations	**83.52**	84.97	63.75
Per unit – diluted	**4.34**	4.51	3.40
Net earnings	**44.50**	35.37	20.63
Per unit – diluted	**2.68**	2.19	1.20
Total assets	**310.57**	277.86	226.96
Net capital expenditures[1]	**63.37**	54.68	56.27
Bank debt	**30.04**	10.34	14.23
Cash distributions	**35.90**	37.44	10.70

1. Amounts include capital expenditures acquired for cash and equity issuances.

CASH DISTRIBUTIONS

Cash distributions to unitholders are at the discretion of the Board of Directors and can fluctuate depending on funds flow from operations. The Trust currently targets a payout ratio of approximately 50 percent of the funds flow attributed to unitholders. The Trust's capital program is financed from available funds flow and additional draw downs on the bank facilities if required. The key drivers of Zargon's funds flow are commodity prices and production volumes. Since the Trust's production is relatively evenly weighted between natural gas (2006 – 55 percent) and oil and liquids (2006 – 45 percent), both commodity prices have a significant effect on its funds flow. In the event that oil and natural gas prices and/or production volumes are higher than anticipated and a cash surplus develops, the surplus may be used to increase distributions, reduce debt, and/or increase the capital program. In the event that oil and natural gas prices and/or production volumes are lower than expected, the Trust may decrease distributions, increase debt and/or decrease the capital program. Zargon regularly reviews its monthly distribution policy in the context of the current commodity price environment, production levels and capital program requirements. Distributions remained constant throughout 2006 at $0.18 per trust unit and have been maintained at this level since November 2005. Cash distributions to unitholders declared for 2006 totalled $35.90 million, resulting in a payout ratio for the year of 43 percent of funds flow from operations or 50 percent on a per diluted trust unit basis.

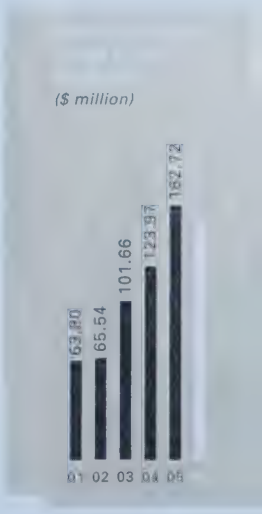
As part of its cash distribution policy, Zargon also considers on a semi-annual basis, the granting of supplemental distributions (over-and-above the monthly distribution). This decision is based on the commodity price environment, tax position, funding requirements for Zargon's exploration and development program and in the future will depend on further clarification of the impact of the recent federal government announcement regarding the taxation of income trusts. The Trust declared a supplemental distribution in December 2005 of $0.50 per trust unit but did not declare any supplemental distributions during 2006.

For Canadian income tax purposes, the 2006 cash distributions are 100 percent taxable income to unitholders.

DETAILED FINANCIAL ANALYSIS

PETROLEUM AND NATURAL GAS

Zargon derives its revenue from the production and sale of petroleum (oil, natural gas liquids) and natural gas. Petroleum and natural gas revenue, exclusive of the impact of financial risk management contracts, decreased five percent to $154.04 million in 2006 from $162.72 million in 2005 primarily due to significantly lower natural gas prices received which were mostly offset by higher oil and liquids prices and a slight increase in overall production. Compared to the prior year, the relative weighting of production revenue between petroleum and natural gas in 2006 was reallocated due to commodity pricing with 55 percent of the revenues coming from the sale of oil and liquids (47 percent in 2005) and 45 percent coming from the sale of natural gas (53 percent in 2005). Production volumes on a barrel of oil equivalent basis in 2006 increased one percent to 8,422 barrels of oil equivalent per day from the prior year amount of 8,342 barrels of oil equivalent per day. Specifically, in 2006 natural gas production decreased one percent and oil and liquids production increased three percent over 2005 levels. Production increases in oil and liquids resulted primarily from the effect of successful ongoing Williston Basin core area exploitation drilling programs. Natural gas production declines resulted from a combination of scheduled and unscheduled third party gas plant maintenance and unpredicted natural gas production declines. The average price of oil and liquids received by Zargon rose to $61.25 per barrel in 2006, up seven percent from 2005. The average field price of natural gas was $6.82 per thousand cubic feet in 2006, a 19 percent decrease over $8.41 per thousand cubic feet in 2005.

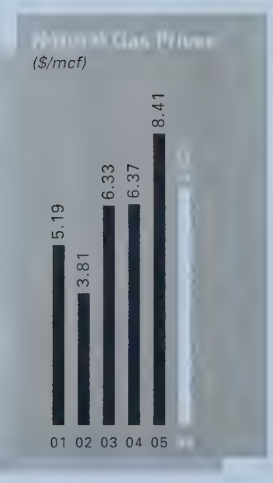


Pricing

Average for the year	**2006**	2005	2004
Natural Gas:			
NYMEX average daily spot price ($US/mmbtu)	**6.75**	8.89	5.90
AECO average daily spot price ($Cdn/mmbtu)	**6.54**	8.77	6.55
Zargon realized field price before the impact of financial risk management contracts ($Cdn/mcf)	**6.82**	8.41	6.37
Zargon realized field price before the impact of physical and financial risk management contracts ($Cdn/mcf)	**6.43**	8.49	6.31
Crude Oil:			
WTI ($US/bbl)	**66.22**	56.56	41.40
Edmonton par price ($Cdn/bbl)	**72.77**	68.72	52.54
Zargon realized field price before the impact of financial risk management contracts ($Cdn/bbl)	**61.25**	57.15	45.37

PETROLEUM (OIL AND NATURAL GAS LIQUIDS) PRICING

Zargon's field oil and natural gas liquids prices are adjusted at the point of sale for transportation charges and oil quality differentials from an Edmonton light sweet crude price that varies with world commodity prices. In 2006, Zargon's average oil and liquids field price, exclusive of the impact of financial risk management contracts, rose seven percent to $61.25 per barrel from $57.15 per barrel in 2005 and $45.37 per barrel in 2004. The field price differential for Zargon's average blended 30 degree API crude stream was $11.52 per barrel less than the 2006 Edmonton reference crude price, which compares to the 2005 differential of $11.57 per barrel and the 2004 differential of $7.17 per barrel. As the quality and weight of Zargon's crude stream have remained relatively consistent for several years, the movements in Zargon's price differential are derived from the North American refinery supply and demand factors for light and medium crudes.



NATURAL GAS PRICING

The average field natural gas price, exclusive of the impact of financial risk management contracts, for 2006 decreased to $6.82 per thousand cubic feet which is 19 percent lower than the 2005 average of $8.41 per thousand cubic feet, and seven percent higher than the 2004 average of $6.37 per thousand cubic feet. Historically, Zargon's field prices have shown a small discount to the benchmark AECO average daily price, due to a lower heating content for Zargon's natural gas and due to legacy aggregator and other contracts which are based partially on monthly index prices that tend to lag the AECO average daily index price in upward or downward trending markets. In 2006, as a result of downward trending natural gas markets, Zargon has realized a small non-recurring premium to the benchmark AECO average daily price due to a combination of fixed price physical contracts and the impact of Zargon receiving AECO monthly index pricing for a portion of its natural gas production. In 2006, the various fixed price physical contracts, which are treated as part of natural gas production revenue and natural gas pricing, created a gain of $2.51 million (2005 – $0.18 million), equivalent to an increase of $0.25 per thousand cubic feet (2005 – $0.02 per thousand cubic feet).

Similar to the prior year, approximately 24 percent of Zargon's 2006 natural gas production was sold under aggregator contracts pursuant to long term contracts. The remainder of Zargon's natural gas production was sold by spot sale contracts and Alberta index prices were received.

RISK MANAGEMENT ACTIVITIES

Zargon's commodity price risk management policy, which is approved by the Board of Directors, allows the use of forward sales and costless collars for a targeted range of 20 to 35 percent of oil and natural gas working interest production volumes, in order to partially offset the effects of large commodity price fluctuations. As both Canadian oil and natural gas field prices are closely correlated to US dollar denominated markets, Zargon will also enter into Cdn/US currency exchange risk management transactions when considered prudent. Because our risk management strategy is protective in nature and is designed to guard the Trust against extreme effects on funds flow from sudden falls in prices and revenues, upward price spikes tend to produce overall losses. Financial risk management contracts in place as at December 31, 2004, were designated as hedges for accounting purposes and the Trust monitored these contracts in determining the continuation of hedge effectiveness. As at June 30, 2006, all designated hedge contracts had expired. For the designated hedge contracts, realized gains and losses were recorded in the statement of earnings as the contracts settled and no unrealized gain or loss was recognized.

For 2006, the total realized risk management loss was $0.57 million compared to a loss of $7.75 million in 2005 and a loss of $4.57 million in 2004. Of the 2006 loss, $4.45 million (equivalent to a reduction of $3.20 per barrel) is related to a loss from oil financial risk management transactions offset by $3.88 million (equivalent to an increase of $0.38 per thousand cubic feet) related to gains from natural gas financial risk management transactions. Oil swaps and collars are settled against the NYMEX pricing index, whereas natural gas swaps, collars and puts are settled against the AECO monthly pricing index. In 2006, NYMEX WTI crude oil prices generally increased throughout the first half of the year, peaking in the month of July. AECO natural gas prices trended downwards during the year. For financial risk management contracts entered into after December 31, 2004, the Trust considers these contracts to be effective on an economic basis but has decided not to designate these contracts as hedges for accounting purposes and accordingly, for these contracts, an unrealized gain or loss is recorded based on the fair value (mark-to-market) of the contracts at year end. The 2006 net unrealized risk management gain totalled $9.55 million which compares to a $3.76 million net unrealized risk management loss in 2005 (2004 – nil). Specifically, the 2006 net unrealized risk management gains resulted from financial oil contract gains ($5.81 million) and financial natural gas contract gains ($3.74 million). These unrealized risk management gains or losses are generated by the change over the reporting period in the mark-to-market valuation of Zargon's future financial contracts. Gains or losses on fixed price physical contracts are included in petroleum and natural gas revenue when settled in the statement of earnings, and no mark-to-market valuation is recorded on these contracts.

As at December 31, 2006, the Trust had the following outstanding commodity price risk management contracts:

Financial Risk Management Contracts

	Rate	Weighted Average Price	Range of Terms
Oil swaps	500 bbl/d	$67.33 US/bbl	Jan. 1/07–Jun. 30/07
	500 bbl/d	$72.70 US/bbl	Jan. 1/07–Dec. 31/07
	500 bbl/d	$72.10 US/bbl	Jul. 1/07–Dec. 31/07
	300 bbl/d	$66.70 US/bbl	Jan. 1/08–Mar. 31/08
	300 bbl/d	$68.29 US/bbl	Apr. 1/08–Jun. 30/08
Natural gas swaps	3,000 gj/d	$9.13/gj	Jan. 1/07–Mar. 31/07
	4,000 gj/d	$8.47/gj	Apr. 1/07–Oct. 31/07
	1,000 gj/d	$8.77/gj	Nov. 1/07–Mar. 31/08
Natural gas collars	1,000 gj/d	$9.50/gj Put; $12.50/gj Call	Jan. 1/07–Mar. 31/07
	1,000 gj/d	$10.50/gj Put; $13.18/gj Call	Jan. 1/07–Mar. 31/07

Physical Risk Management Contracts

	Rate	Weighted Average Price	Range of Terms
Natural gas fixed price	2,000 gj/d	$9.23/gj	Jan. 1/07–Mar. 31/07
	1,000 gj/d	$7.88/gj	Apr. 1/07–Oct. 31/07
Natural gas collars	1,000 gj/d	$8.50/gj Put; $12.85/gj Call	Jan. 1/07–Mar. 31/07
	1,000 gj/d	$9.50/gj Put; $13.50/gj Call	Jan. 1/07–Mar. 31/07

ROYALTIES

Royalties include payments made to the Crown, freehold owners and third parties. Reported royalties also include the cost of the Saskatchewan Resource Surcharge (SRC), the cost of North Dakota state taxes and credits received through the Alberta Royalty Credit (ARC) program. During 2006, total royalties were $33.43 million, a decrease of 10 percent from $37.32 million in 2005. Royalties as a percentage of gross revenue were 21.7 percent in 2006 compared to 22.9 percent in 2005 and 22.6 percent in 2004. On a commodity basis, natural gas royalties averaged 20.8 percent in 2006, a decrease from the previous year's average of 23.3 percent. This decline is attributed to the effect of gains recognized on fixed price physical contracts and from the impact of Zargon receiving AECO monthly index pricing for a portion of its natural gas sales. Oil royalties averaged 22.4 percent, relatively unchanged from the prior year's rate of 22.5 percent, as was expected.

During 2006, 60 percent (2005 – 61 percent) of the total royalties were paid to provincial and state governments, with the remainder paid to freehold owners and other third parties. Royalties payable to the Province of Alberta on qualifying properties are reduced through the ARC program. Zargon earned the maximum $0.50 million ARC rebate in 2006, which is the same amount received in both 2005 and 2004. During the third quarter of 2006, the Alberta provincial government announced the elimination of the Alberta Royalty Credit effective January 1, 2007. The SRC charges were $1.01 million in 2006, relatively even with $1.03 million in the prior year and up from $0.64 million in 2004, reflecting the trend in Saskatchewan oil revenues. North Dakota state taxes increased to $2.27 million in 2006 from $1.82 million in the prior year, primarily due to increased prices for oil, as well as slightly increased production in the state.

PRODUCTION EXPENSES

Zargon's production expenses increased 10 percent to $26.42 million in 2006, from $24.04 million in 2005. On a unit of production basis, production expenses increased nine percent to $8.59 per barrel of oil equivalent from $7.89 in 2005 ($7.21 in 2004).

Natural gas production expenses in 2006 rose 11 percent to $1.05 per thousand cubic feet from $0.95 per thousand cubic feet in 2005. The primary reasons for the increase are due to increased gas gathering charges, increased rentals for compression equipment, increased water disposal and water hauling costs, all part of the industry-wide trend of higher operating costs.

Oil production expenses also rose in 2006 to $11.40 per barrel, an increase of seven percent from $10.64 per barrel in 2005. The primary reasons for the increase are due to increased costs industry-wide, particularly for electricity, propane and well servicing.

Due to the high levels of industry activity caused by the high commodity price environment, there was increasing upward pressure on per unit operating costs. In 2006, 2005 and 2004, Zargon's costs increased substantially due in general to the effect of industry-wide higher cost trends. This trend culminated with a $9.92 per barrel of oil equivalent operating cost in the fourth quarter of 2006, a level which included a prior period adjustment of $0.40 per barrel of oil equivalent relating primarily to third party natural gas processing costs. Going forward in 2007, Zargon is forecasting an average production expense of $9.25 per barrel of oil equivalent.

OPERATING NETBACKS

The average oil and liquids price received, after realized risk management losses, in 2006 of $58.05 per barrel was nine percent higher than the $53.32 per barrel received in 2005, while the average natural gas price received, after realized risk management gains/losses, in 2006 of $7.21 per thousand cubic feet was 12 percent below the $8.16 per thousand cubic feet received in 2005. Operating netbacks increased/decreased commensurately. Oil and natural gas liquids netbacks rose 11 percent to $32.93 per barrel from $29.80 per barrel in 2005. Natural gas netbacks decreased 10 percent to $4.73 per thousand cubic feet from $5.25 per thousand cubic feet in 2005. On a barrel of oil equivalent basis, 2006 operating netbacks declined one percent to $30.46 from $30.75 in 2005.

Operating Netbacks

	2006		2005	
	Oil and Liquids ($/bbl)	**Natural Gas ($/mcf)**	Oil and Liquids ($/bbl)	Natural Gas ($/mcf)
Production revenue	**61.25**	**6.82**	57.15	8.41
Realized risk management gain/(loss)	**(3.20)**	**0.38**	(3.83)	(0.25)
Royalties	**(13.72)**	**(1.42)**	(12.88)	(1.96)
Production costs	**(11.40)**	**(1.05)**	(10.64)	(0.95)
Operating netbacks	**32.93**	**4.73**	29.80	5.25

GENERAL AND ADMINISTRATIVE

Gross general and administrative costs increased 14 percent in 2006 to $10.25 million from $8.96 million in 2005. On a per unit of production basis, net general and administrative costs increased 14 percent to $2.27 per barrel of oil equivalent, compared to $1.99 per barrel of oil equivalent in 2005 and $1.45 in 2004. Trending upwards from 2004, the 2005 increased general and administrative costs on a per unit of production basis were due to increases in staff costs, performance-based compensation costs, regulatory reporting requirements and the additional legal and other outside advisory costs of operating as a trust. In 2006, the further increase on a per unit of production basis was impacted by additional office lease costs, and the costs related to the expansion of Zargon's technical staff.

General and Administrative Expenses

($ million, except as noted)	2006	2005	2004
Gross general and administrative expenses	10.25	8.96	7.23
Overhead recoveries	(3.28)	(2.91)	(2.87)
Net general and administrative expenses	6.97	6.05	4.36
Net expense after recoveries ($/boe)	2.27	1.99	1.45
Number of office employees at year end	43	39	35

INTEREST AND FINANCING CHARGES

Zargon's borrowings are through its syndicated bank credit facilities. Interest and financing charges were $1.53 million compared to $0.79 million in 2005. An increase in the average debt level and increases in borrowing rates are the primary reasons for the increase in interest and financing charges. Zargon's effective interest and financing charge rate was 6.4 percent on an average bank debt of $23.84 million in 2006, compared to 4.3 percent on an average bank debt of $18.17 million in 2005 and 4.9 percent on an average bank debt of $8.88 million in 2004. At year end 2006, Zargon's bank debt, net of working capital (excluding unrealized risk management assets and liabilities), totalled $39.83 million, up 45 percent from $27.49 million at December 31, 2005.

On June 30, 2006, Zargon amended and renewed its syndicated committed credit facilities, which resulted in an increase in the available facilities and borrowing base to $100 million from the previous amount of $80 million. The next renewal date is July 31, 2007.

CAPITAL AND CURRENT INCOME TAXES

Capital and current income taxes for 2006 were $1.60 million compared to $1.80 million in 2005. Of the total, $1.34 million is due to current taxes incurred in the United States compared to $0.90 million in 2005. The increased taxable income in the United States is due to declining tax pools and higher revenue in 2006 resulting in higher United States taxes. Provided that oil prices remain high, a similar level of United States current income taxes is predicted in 2007. The remaining current tax amounts relate to Canadian federal and provincial capital and withholding taxes, which were $0.26 million in 2006 compared to $0.90 million in 2005. This year-over-year decline was primarily the result of second quarter 2006 legislation substantively enacted by the Canadian Federal Government which eliminated the federal capital tax effective January 1, 2006. Tax pools as at December 31, 2006 were approximately $113 million which represents an increase from the comparable $90 million of tax pools available to Zargon at the end of 2005. The Trust is a taxable entity under the Income Tax Act (Canada) and currently is taxable only on the income that is not distributed or declared distributable to unitholders. For Canadian income tax purposes, 2006 distributions are 100 percent taxable income to unitholders.

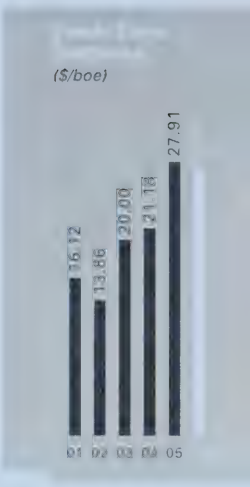
On October 31, 2006, the Federal Government announced tax proposals pertaining to the taxation of distributions paid by trusts and the personal tax treatment of trust distributions. Currently, the Trust does not pay tax on distributions as tax is paid by the unitholders. If enacted, the proposals would result in taxation of distributions at the Trust level at a rate of 31.5 percent effective January 1, 2011. As the proposals are not yet enacted, there was no impact on the results of the Trust for the year ended December 31, 2006. The Trust is currently assessing the proposals and the potential implications to the Trust.

TRUST NETBACKS

Historically high oil prices and the continued strength of natural gas prices in 2006 resulted in relatively strong revenue netbacks and operating netbacks. On a barrel of oil equivalent basis, revenue of $50.11 in 2006 was six percent lower than the prior year and operating netbacks as well as funds flow netbacks decreased one percent and three percent over the prior year to $30.46 and $27.17 per barrel of oil equivalent, respectively.

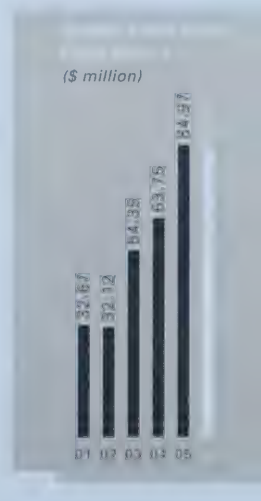
Trust Netbacks

($/boe)	2006	2005	2004
Petroleum and natural gas revenue	**50.11**	53.44	41.20
Realized risk management loss	**(0.18)**	(2.55)	(1.52)
Royalties	**(10.88)**	(12.25)	(9.32)
Production costs	**(8.59)**	(7.89)	(7.21)
Operating netbacks	**30.46**	30.75	23.15
General and administrative	**(2.27)**	(1.99)	(1.45)
Interest and financing charges	**(0.50)**	(0.26)	(0.15)
Capital and current income taxes	**(0.52)**	(0.59)	(0.37)
Funds flow netbacks	**27.17**	27.91	21.18
Depletion and depreciation	**(13.38)**	(12.31)	(9.11)
Unrealized risk management gain/(loss)	**3.11**	(1.24)	–
Accretion of asset retirement obligations	**(0.41)**	(0.39)	(0.36)
Unit-based compensation	**(0.60)**	(0.30)	(1.22)
Unrealized foreign exchange gain/(loss)	**(0.01)**	0.07	0.19
Future income tax recovery/(expense)	**0.92**	(0.16)	(3.20)
Earnings before non-controlling interest	**16.80**	13.58	7.48

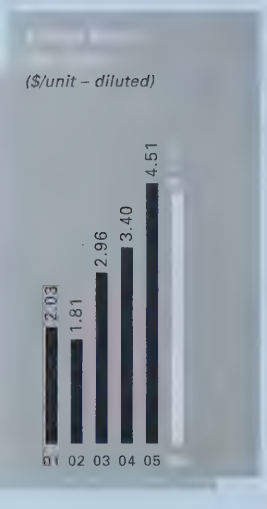


FUNDS FLOW FROM OPER

In 2006, production volumes held steady, but the increase of seven percent in oil and natural gas liquids prices received was more than offset by a 19 percent decline in natural gas prices received, producing a two percent decline in funds flow from operations to $83.52 million, compared to $84.97 million in 2005 and $63.75 million in 2004. The corresponding funds flow per diluted unit was $4.34 in 2006, a four percent decline from $4.51 in 2005, and $3.40 in 2004. The diluted per unit statistics reflect a two percent increase in the weighted average outstanding units to 19.24 million in 2006, and a one percent increase in the average weighted number of outstanding units to 18.85 million in 2005 from 18.72 million in 2004.



The following table summarizes the variances in funds flow from operations between 2005 and 2006. It shows that the variance is caused mainly by decreased commodity pricing, with partial offset coming from decreased royalties and lower realized risk management losses.



	$ Million	$ Per Diluted Trust Unit	Per Unit Percent Variance
Funds flow from operations - 2005	**84.97**	**4.51**	**–**
Price variance	(10.24)	(0.53)	(12)
Volume variance	1.56	0.08	2
Realized risk management losses	7.19	0.37	8
Royalties	3.89	0.20	5
Expenses:			
Production	(2.38)	(0.12)	(3)
General and administrative	(0.92)	(0.05)	(1)
Interest and financing charges	(0.75)	(0.04)	(1)
Current taxes	0.20	0.01	–
Weighted average trust units - diluted	–	(0.09)	(2)
Funds flow from operations - 2006	**83.52**	**4.34**	**(4)**

DEPLETION AND DEPRECIATION

In 2006, Zargon's depletion and depreciation provision increased 10 percent to $41.14 million, compared to $37.48 million in 2005 and $27.41 million in 2004. The higher charges reflect an increase of one percent in production volumes and a nine percent increase in the charge on a per barrel of oil equivalent basis. The primary reasons for the year-over-year expense increase on a per barrel of oil equivalent basis are due to the increase in the property and equipment balance from normal operations, from the impact of the conversion of exchangeable shares due to the application of EIC-151 and also as a result of second quarter 2006 and third quarter 2005 production losses and the related reserve adjustments due to the watering out of wells located at the Sturgeon Lake, Highvale, Judy Creek and Progress properties in the West Central Alberta core area.

Depletion and depreciation charges calculated on a unit of production method are based on total proved reserves with a conversion of six thousand cubic feet of natural gas being equivalent to one barrel of oil. The 2006 depletion calculation includes $14.11 million of future capital expenditures to develop the Trust's reserves, but excludes $20.99 million of unproven properties relating to undeveloped land.

Zargon's depletion and depreciation, on a barrel of oil equivalent basis, increased nine percent in 2006 to $13.38 from $12.31 in 2005 and $9.11 in 2004. Depletion and depreciation rates will be subject to continuing upward pressure as industry finding and development costs increase to reflect the new economics of the recent trends to relatively higher commodity prices.

ACCRETION OF ASSET RETIREMENT OBLIGATIONS

For the year ended December 31, 2006, the non-cash accretion expense for asset retirement obligations is $1.24 million compared to $1.20 million in 2005 and $1.08 million in 2004. The year-over-year increases are due to changes in the estimated future liability for asset retirement obligations as a result of wells added through Zargon's drilling program. The significant assumptions used in this calculation are a credit adjusted risk-free rate of 7.5 percent, an inflation rate of two percent and the payments to settle the retirement obligations occurring over the next 30 years with the majority of the costs being incurred after 2012. The estimated net present value of the total asset retirement obligation is $17.31 million as at December 31, 2006, based on a total future liability of $65.08 million.

UNIT-BASED COMPENSATION

Unit-based compensation was $1.86 million in 2006 or $0.96 million higher than the $0.90 million expense in 2005. The Trust generally grants unit rights on a quarterly basis. The increase in the expense is as a result of these new unit rights granted throughout 2006 and the vesting of unit rights previously granted. Zargon will continue to use fair value methodologies, where possible, for future unit rights grants. These non-cash expenses will be recurring charges in future years if Zargon continues to grant employees and directors trust unit rights.

The trust unit rights incentive plan allows the Trust to issue rights to acquire trust units to directors, officers, employees and other service providers. The Trust is authorized to issue up to 1.82 million unit rights; however, the number of trust units reserved for issuance upon exercise of the rights shall not exceed 10 percent of the aggregate number of issued and outstanding trust units of the Trust. The plan allows for the holder of rights to either exercise the right based on the original grant price or on the original grant price reduced by a portion of the future distributions. Unit right grant prices are set at the market price for the trust units on the date the unit rights are issued. Trust unit rights granted under the plan generally vest over a three-year period and expire approximately five years from the grant date.

FUTURE INCOME TAXES

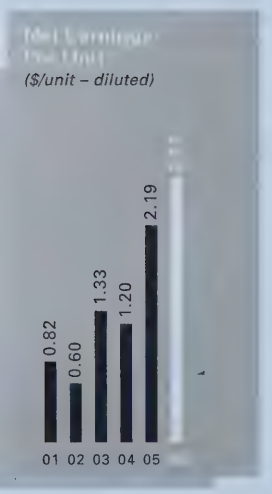
The provision for future tax recovery for 2006 was $2.82 million when compared to a future tax expense of $0.47 million in 2005 and an expense of $9.64 million in 2004. Effectively, Zargon's future tax obligations are reduced as distributions are made from the Trust and consequently it is anticipated that Zargon's effective tax rate will continue to be low. The 2006 year includes a second quarter recovery of $6.01 million relating to a reduction in future federal and provincial income tax rates substantively enacted during the 2006 second quarter and includes the impact of certain tax balance adjustments.

NON-CONTROLLING INTEREST-EXCHANGEABLE SHARES

On January 19, 2005, the CICA issued EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" that states that exchangeable securities issued by a subsidiary of an Income Trust should be reflected as either a non-controlling interest or debt on the consolidated balance sheet unless they meet certain criteria. The exchangeable shares issued by Zargon Oil & Gas Ltd., a corporate subsidiary of the Trust, are publicly traded and have an expiry term, which could be extended at the option of the Board of Directors. Therefore, these securities are considered, by EIC-151, to be transferable to third parties and to have an indefinite life. EIC-151 states that if these criteria are met, the exchangeable shares should be reflected as a non-controlling interest. Prior to 2005, these exchangeable shares were reflected as a component of unitholders' equity.

As a result of this 2005 change in accounting policy, the Trust has increased its unitholders' equity and non-controlling interest for 2006 by $12.12 million (2005 – $24.44 million) on the Trust's consolidated balance sheet. Consolidated net earnings for 2006 have been reduced for net earnings attributable to the non-controlling interest of $7.14 million (2005 – $5.99 million). In accordance with EIC-151 and given the circumstances in Zargon's case, each redemption is accounted for as a step-purchase, which for 2006 additionally resulted in an increase in property and equipment of $6.73 million (2005 – $24.93 million), and an increase in future income tax liability of $1.75 million (2005 – $6.48 million). Funds flow from operations were not impacted by this change.

The cumulative impact to date of the application of EIC-151 has been to increase gross property and equipment by $42.94 million, (for depletion impact see note 4 in the audited consolidated financial statements), unitholders' equity and non-controlling interest by $46.71 million, future income tax liability by $11.23 million and an allocation of net earnings to exchangeable shareholders of $15.00 million.



NET EARNINGS

Zargon's 2006 net earnings were $44.50 million, a $9.13 million increase from $35.37 million in 2005. The 2004 net earnings were $20.63 million. The net earnings track the funds flow from operations for the respective periods modified by non-cash charges, which in 2006 include depletion and depreciation, unrealized risk management gains, future income tax recoveries, unit-based compensation and non-controlling interest. On a per diluted unit basis, 2006 net earnings were $2.68 compared to $2.19 in 2005 and $1.20 in 2004.

On a barrel of oil equivalent basis, the 2006 earnings before non-controlling interest were $16.80 compared to $13.58 in 2005 and $7.48 in 2004.

The 2006 net earnings were 53 percent of funds flow from operations, primarily reflecting the increase in unrealized risk management gains and the reduction in future income taxes. The 2005 net earnings represented 42 percent of funds flow from operations compared to 32 percent of funds flow in 2004.

CAPITAL EXPENDITURES

Net capital expenditures in 2006 of $63.37 million increased 16 percent from $54.68 million in 2005. In 2006, Zargon completed an expanded drilling program of 89 gross (76.2 net) wells and drilling and completion expenditures climbed commensurately by 25 percent to $41.80 million. Of the total 2006 net capital expenditures, $18.29 million were expended on West Central Alberta, $22.95 million on Alberta Plains and $22.13 million on Williston Basin properties.

Capital Expenditures

($ million)	**2006**	2005	2004
Undeveloped land	**5.25**	3.65	3.84
Geological and geophysical (seismic)	**3.34**	3.47	5.26
Drilling and completion of wells	**41.80**	33.36	26.94
Well equipment and facilities	**16.12**	11.78	8.42
Exploration and development	**66.51**	52.26	44.46
Property acquisitions	**1.40**	3.68	12.09
Property dispositions	**(4.54)**	(2.45)	(0.28)
Net property acquisitions/(dispositions)	**(3.14)**	1.23	11.81
Corporate acquisitions assigned to property and equipment[1]	**–**	1.19	–
Total net capital expenditures[1]	**63.37**	54.68	56.27

1. Amounts include capital expenditures acquired for cash and equity issuances.

LIQUIDITY AND CAPITAL RESOURCES

In 2006, the summation of the funds outflows pertaining to the net capital expenditure program ($63.37 million) and the cash distributions to unitholders ($35.90 million) exceeded by $11.73 million the summation of the funds inflows coming from the funds flow from operations ($83.52 million) plus the proceeds from the issuance of trust units ($4.02 million).

Zargon's financing philosophy and three sources of funding are as follows:

- Internally generated funds flow from operations provides the basic level of funding for the Trust's annual capital expenditures program and for distributions to unitholders.
- Debt may be utilized for acquisitions or to expand capital programs when it is deemed appropriate. The Trust has $100 million in syndicated committed credit facilities. As at December 31, 2006, $69.96 million or 70 percent of these facilities are unutilized.
- New equity, if available and if on favourable terms, can be utilized for acquisitions or to expand capital programs.

The recently announced changes to the Canadian income trust tax rules after 2010 may have negatively impacted the Canadian oil and gas trust industry's access to new capital from debt and equity markets in the future.

Capital Sources

($ million)	**2006**	2005	2004
Funds flow from operations	**83.52**	84.97	63.75
Change in bank debt	**19.70**	(3.89)	7.25
Issuance of trust units	**4.02**	3.87	2.87
Cash distributions to unitholders	**(35.90)**	(37.44)	(10.70)
Changes in working capital and other	**(7.97)**	7.17	2.54
Reorganization costs	**–**	–	(9.44)
Total capital sources	**63.37**	54.68	56.27

FUNDS FLOW FROM OPERATIONS

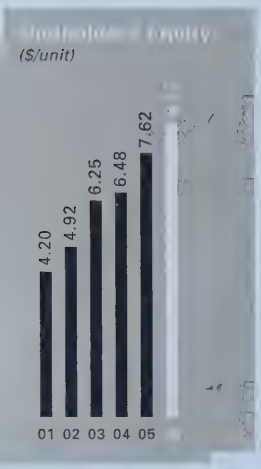
It is anticipated that Zargon's 2007 exploration and development capital budget and cash distributions to unitholders will be financed through the Trust's funds flow from operations. Funds flow is partially influenced by factors that the Trust cannot control, such as commodity prices, the US/Canadian dollar exchange rates and interest rates. Zargon's 2007 estimated sensitivity to moderate fluctuations in these key business parameters is shown in the accompanying table.

Funds Flow Sensitivity Summary

	Change in 2007 Funds Flow	
	($ million)	($/unit)
Change of $1.00 US/bbl in the price of WTI oil	0.80	0.04
Change in oil production of 100 bbl/d	0.92	0.05
Change of $0.10 US/mcf in the price of NYMEX natural gas	0.73	0.04
Change in natural gas production of one mmcf/d	1.49	0.08
Change in $0.01 in the $US/$Cdn exchange rate	1.32	0.07

BANK DEBT

On September 30, 2005, a Canadian subsidiary and a US subsidiary of the Trust entered into syndicated committed credit facilities with a borrowing base of $80 million which replaced its former demand facility of $50 million. These facilities consisted of a $60 million tranche available to the Canadian borrower and a US $15 million tranche available to the US borrower. On June 30, 2006, Zargon amended and renewed these syndicated committed credit facilities, the result of which is an increase in the available facilities and borrowing base to $100 million from the previous amount of $80 million. These facilities consist of an $80 million tranche available to the Canadian borrower and a US $15 million tranche available to the US borrower. A $150 million demand debenture on the assets of the subsidiaries of the Trust has been provided as security for these facilities. The facilities are fully revolving for a 364 day period with the provision for an annual extension at the option of the lenders and upon notice from Zargon's management. The next renewal date is July 31, 2007. Should the facilities not be renewed, they convert to one year non-revolving term facilities at the end of the revolving 364 day period. Repayment would not be required until the end of the non-revolving term, and as such, these facilities have been classified as long term debt. At December 31, 2006, bank debt was $30.04 million, an increase of $19.70 million from the prior year end bank debt amount of $10.34 million.



Zargon's debt net of working capital (excluding unrealized risk management assets and liabilities) of $39.83 million at December 31, 2006 was equivalent to 48 percent of the 2006 funds flow from operations of $83.52 million. At December 31, 2005, the debt net of working capital (excluding unrealized risk management assets and liabilities) was $27.49 million, equivalent to 32 percent of the 2005 funds flow from operations of $84.97 million.

EQUITY

At March 12, 2007, Zargon had 16.894 million trust units and 2.133 million exchangeable shares outstanding. Assuming full conversion of exchangeable shares at the effective exchange ratio of 1.21149, there would be 19.478 million trust units outstanding at this date. Pursuant to the trust unit rights incentive plan, there are currently an additional 1.311 million trust unit incentive rights issued and outstanding.

During 2006, 10.80 million Zargon trust units traded on The Toronto Stock Exchange with a high trading price of $34.75 per unit, a low of $24.10 per unit and a closing price of $24.79 per unit. The 2006 trading statistics show an 18 percent year-over-year decrease in trading volume, and a 22 percent decrease in the closing unit price. Zargon's market capitalization (including the market value of exchangeable shares) at year end 2006 was approximately $482 million, compared to approximately $603 million at the end of 2005.

SEGMENTED GEOGRAPHIC INFORMATION

In calendar 2006, approximately 84 percent (2005 – 87 percent) of Zargon's combined petroleum and natural gas revenue came from Western Canadian (Alberta, Saskatchewan and Manitoba) properties, with the remaining 16 percent (2005 – 13 percent) of revenues generated in the United States (North Dakota).

OFF BALANCE SHEET ARRANGEMENTS

The Trust has no guarantees or off balance sheet arrangements, except for letters of credit which have been issued in the normal course of business of approximately $0.47 million as at December 31, 2006.

RELATED PARTY TRANSACTIONS

During the year, the Trust paid $0.05 million (2005 – $0.04 million) for vehicle leases to a company owned by a Board member; $0.09 million (2005 – $0.12 million) for legal services to a law firm in which a Board member is a partner; $0.02 million (2005 – $0.01 million) for field services to a company of which a senior Zargon officer is a Board member and nominal shareholder; and $0.06 million (2005 – $0.13 million) in consulting fees to a company owned by the Chairman of the Board. All amounts were based on normal commercial terms and conditions.

CONTRACTUAL OBLIGATIONS

Zargon has certain contractual obligations relating to the lease of head office space, field operating leases and transportation contracts that extend for longer than one year as set out in the table below:

($ million)	Total	2007	2008 to 2009	2010 to 2011	Thereafter
Head office lease and other	6.73	1.16	2.45	2.42	0.70
Field operating leases	0.04	0.04	-	-	-
Transportation contracts	0.92	0.73	0.19	-	-
Total	7.69	1.93	2.64	2.42	0.70

CRITICAL ACCOUNTING ESTIMATES

The preparation of the consolidated financial statements in accordance with Canadian generally accepted accounting principles requires management to make judgments and estimates that affect the financial results of the Trust. Zargon's management reviews its estimates regularly, but new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates. The critical estimates are discussed below:

PETROLEUM AND NATURAL GAS RESERVES

All of Zargon's petroleum and natural gas reserves are evaluated and reported on by independent petroleum engineering consultants in accordance with Canadian Securities Administrators' National Instrument 51-101 ("NI 51-101"). The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, commodity prices and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Trust expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels and changes in costs and commodity prices.

FULL COST ACCOUNTING

Zargon follows the full cost method of accounting for petroleum and natural gas operations as outlined in Canadian Institute of Chartered Accountants ("CICA") accounting guideline "Oil and Gas Accounting–Full Cost" (AcG-16). Under this accounting method, all costs related to the exploration for and development of petroleum and natural gas reserves are capitalized. Capitalized costs, as well as the estimated future expenditures to develop proved reserves, are depleted using the unit-of-production method based on estimated proved oil and natural gas reserves.

In applying the full cost method, Zargon calculates a ceiling test on a quarterly basis to ensure that the net carrying value of petroleum and natural gas assets do not exceed the estimated undiscounted future net cash flow from production of proved reserves. Accordingly, the Trust must base this calculation of future net cash flow on estimated forecasted sales prices, costs and regulations in effect at the period end. AcG-16 limits the carrying value of petroleum and natural gas properties to their fair value. The fair value is equal to estimated future cash flow from proved and probable reserves using future price forecasts and costs discounted at a risk-free rate.

ASSET RETIREMENT OBLIGATIONS

Zargon follows CICA Section 3110, "Asset Retirement Obligations", which requires liability recognition for retirement obligations associated with the Trust's property, plant and equipment. Under this policy, the Trust is required to provide for future removal and site restoration costs. The Trust must estimate these costs in accordance with existing laws, contracts or other policies and must also estimate a credit adjusted risk-free rate and inflation rate in this calculation. These estimated costs are charged to earnings and the appropriate liability account over the expected life of the asset. When the future removal and site restoration costs cannot be reasonably determined, a contingent liability may exist. Contingent liabilities are charged to earnings when management is able to determine the amount and the likelihood of the future obligation.

INCOME TAX ACCOUNTING

The determination of the Trust's income and other tax liabilities requires interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

RECENT CANADIAN ACCOUNTING PRONOUNCEMENTS

As of January 1, 2007, the Trust is required to adopt CICA Section 1530 *"Comprehensive Income"*, Section 3251 *"Equity"*, Section 3855 *"Financial Instruments–Recognition and Measurement"*, and Section 3865 *"Hedges"*, which were issued in January 2005. Under the new standards, a new financial statement, the Consolidated Statement of Comprehensive Income, has been introduced that will provide for certain gains and losses and other amounts arising from changes in fair value, to be temporarily recorded outside the income statements. In addition, all financial instruments, including derivatives, are to be included in the Trust's Consolidated Balance Sheets and measured, in most cases, at fair values, and requirements for hedge accounting have been further clarified. The Trust is currently evaluating the impact of the new standards. Management does not anticipate the new and revised standards will have a material impact on its consolidated financial statements as the Trust currently uses fair value accounting for derivative instruments that do not qualify or are not designated as hedges.

As of January 1, 2007, the Trust is required to adopt revised CICA Section 1506, *"Accounting Changes"*, which provides expanded disclosures for changes in accounting policies, accounting estimates and corrections of errors, which were issued in July 2006. Under the new standard, accounting changes should be applied retrospectively unless otherwise permitted or where impracticable to determine. As well, voluntary changes in accounting policy are made only when required by a primary source of GAAP or when the change results in more relevant and reliable information. The Trust does not expect application of this revised standard to have a material impact on its consolidated financial statements.

MANAGEMENT AND FINANCIAL REPORTING SYSTEMS

DESIGN OF INTERNAL CONTROL OVER FINANCIAL REPORTING AND DISCLOSURE CONTROL AND PROCEDURES

The Trust has designed internal controls over financial reporting and has established procedures and internal control systems to ensure timely and accurate preparation of financial, internal management and other reports. Disclosure controls and procedures are in place to ensure all ongoing statutory reporting requirements are met and material information is disclosed on a timely basis. The President and Chief Executive Officer and the Executive Vice President and Chief Financial Officer, individually, sign certifications that the financial statements together with the other financial information included in the regulatory filings fairly present in all material respects the financial conditions, results of operations and cash flows as of the dates and for the periods represented.

Our management, including our President and Chief Executive Officer and the Executive Vice President and Chief Financial Officer, have designed internal controls over financial reporting and have evaluated the effectiveness of the Trust's disclosure controls and procedures as at the end of the period covered by this report. Based on the above, the President and Chief Executive Officer and the Executive Vice President and Chief Financial Officer, have concluded that the Trust has designed internal controls over financial reporting and the Trust's disclosure controls are effective as at the end of the period covered by this annual report, in all material respects, after considering the Canadian Securities Administrator's Multilateral Instrument 52-109 "Certification of Disclosures in Issuers' Annual and Interim Filings."

Because of their inherent limitations, disclosure controls and procedures and internal controls over financial reporting may not prevent or detect misstatements, errors or fraud. Control systems, no matter how well conceived or operated, can provide only reasonable, not absolute assurance that the objectives of the control systems are met.

BUSINESS RISKS AND OUTLOOK

BUSINESS RISKS

Zargon's external business risks arise from the uncertainty of oil and natural gas pricing, the uncertainty of interest and exchange rates, environmental and safety issues and financial and liquidity considerations. Additional risk arises from the production performance of existing properties (including natural decline), the changes in tax, royalty and other regulatory standards and uncertain results from capital expenditure programs.

Oil and natural gas prices may fluctuate widely in response to many factors such as global and North American supply and demand, economic conditions, weather conditions, political stability, the supply and price of imported oil and liquefied natural gas, production and storage levels of North American natural gas and government regulations. Zargon attempts to minimize pricing and currency exchange uncertainty with a risk management program that encompasses a variety of financial instruments. These could include forward sales of oil and natural gas production (either through financial derivative transactions such as swaps or by physical contracts), put options on both oil and natural gas, costless collars (in which some potential high price gain is given up in return for potential low price support) and US dollar currency risk management transactions in different forms for up to 35 percent of its oil and natural gas production volumes. In general, the Trust seeks to use strategies that allow minimum price expectations to be met in order that distributions and capital programs can be funded. This strategy is designed mainly to protect the Trust against periods of unusually low commodity prices and by its nature is likely to produce significant risk management losses when prices are unusually high.

Environmental and safety risks are mitigated through compliance with provincial and federal environmental and safety regulations, by maintaining adequate insurance and by adopting appropriate emergency response and employee safety procedures.

The Trust is subject to a broad range of laws and regulatory requirements. Changes in government regulations, including reporting requirements, income tax laws, operating practices, environmental protection requirements and royalty rates can have a significant impact on Zargon. Although Zargon has no control over these regulatory risks, the Trust actively monitors changes, participates in industry organizations and, when required, engages the assistance of third party experts to assess the impact of such changes on the Trust's financial and operating results.

Financial and liquidity risks are reduced by limiting debt financing to self-imposed debt to funds flow guidelines. Zargon maintains a low cash distribution to funds flow from operations ratio to ensure adequate funding is available for capital programs to sustain per unit production and reserves. Access to capital markets, if required for additional financing by either debt or equity issuances, is dependent upon maintaining strong performance and relationships with investors. A substantial portion of the Trust's accounts receivable are with companies in the oil and gas industry and are subject to normal industry credit risks. Management regularly monitors the ageing of receivable balances to mitigate this risk. With respect to financial instruments utilized for risk management purposes, the Trust partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

The recently announced changes to the Canadian income trust tax rules after 2010 may have negatively impacted the Canadian oil and gas trust industry's access to new capital from debt and equity markets in the future.

Zargon actively manages the risks of its capital programs and reserves by concentrating drilling and subsequent development activities in areas where it has demonstrated proven technical capabilities and understanding. Zargon's capital budget is managed to limit exposure so that significant capital is not risked on any one project or concept.

OUTLOOK

As a sustainable trust, Zargon is committed to maintaining reserves, production and distributions per trust unit in the context of distributing approximately 50 percent of its funds flow from operations to unitholders. For calendar 2007, Zargon has budgeted $55 million of capital expenditures allocated to natural gas exploration and oil exploitation and is projecting an average production rate of approximately 8,750 barrels of oil equivalent per day. This amount does not include any allocation for opportunistic corporate or property acquisitions which, if available, would be funded by bank debt or equity issuances.

SELECTED QUARTERLY INFORMATION

	2006				2005			
($ million, except per unit amounts)	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Petroleum and natural gas revenue	**36.50**	**37.93**	**38.66**	**40.94**	50.26	42.47	35.87	34.12
Funds flow from operations	**19.01**	**20.04**	**22.13**	**22.35**	26.62	21.85	19.01	17.48
Per unit – diluted	**0.98**	**1.03**	**1.14**	**1.17**	1.40	1.15	1.01	0.93
Net earnings	**7.05**	**12.31**	**13.22**	**11.92**	17.45	6.30	6.48	5.14
Per unit – diluted	**0.43**	**0.73**	**0.79**	**0.72**	1.06	0.39	0.41	0.32
Cash distributions	**9.05**	**9.00**	**8.96**	**8.89**	16.66	7.45	6.73	6.60
Per trust unit	**0.54**	**0.54**	**0.54**	**0.54**	1.02	0.46	0.42	0.42
Net capital expenditures[1]	**20.41**	**18.99**	**8.78**	**15.19**	19.12	13.91	10.96	10.69
Total assets	**310.57**	**294.14**	**283.86**	**282.35**	277.86	264.44	253.75	245.20
Bank debt	**30.04**	**20.71**	**18.14**	**26.64**	10.34	11.43	15.52	18.23

1. Amounts include capital expenditures acquired for cash and equity issuances.

FOURTH QUARTER 2006 RESULTS

During the fourth quarter of 2006, Zargon's petroleum and natural gas revenues of $36.50 million were four percent lower than the previous quarter's revenues. Production for the 2006 fourth quarter of 8,366 barrels of oil equivalent per day fell short of the fourth quarter guidance of 8,500 barrels of oil equivalent per day by two percent and was two percent higher than the 2006 third quarter's production of 8,194 barrels of oil equivalent per day. Compared to the previous quarter, oil production increased two percent to 3,789 barrels per day as Williston Basin horizontal wells were placed on production. Fourth quarter natural gas production increased two percent over the previous quarter to 27.46 million cubic feet per day as recently drilled West Central Alberta and Alberta Plains natural gas wells were tied-in. Average field prices received during the fourth quarter, before the impact of financial risk management contracts, were $54.69 per barrel for oil and liquids and $6.90 per thousand cubic feet for natural gas, a 19 percent reduction and a 15 percent increase, respectively, compared to the 2006 third quarter prices. Reflecting market and seasonal trends, Zargon's field price differential for its blended 30 degree API crude oil stream decreased to a $9.80 per barrel discount to the Edmonton reference crude oil price, a 19 percent decrease from Zargon's average differential of $12.09 per barrel for the first nine months of 2006.

Funds flow from operations was $19.01 million in the fourth quarter, a decrease of five percent or $1.03 million over the prior quarter. A comparative analysis of the primary factors that caused this quarter-over-quarter decrease is as follows:

- Realized risk management gains increased by $0.82 million to $1.16 million, a 244 percent increase over the prior quarter's $0.34 million of risk management gains. The primary reason for this increase in the fourth quarter related to gains on financial natural gas risk management contracts due to the lower natural gas prices received throughout the quarter.

- Royalties for the fourth quarter were $7.84 million, a decrease of $0.64 million from the prior quarter. The average royalty rate for the quarter declined to 21.5 percent from 22.3 percent from the third quarter. This decline is attributed to the effect of fourth quarter gains recognized on fixed price physical natural gas contracts which increase natural gas pricing and revenue.

- Production expenses increased to $7.64 million for the quarter, a $0.66 million or nine percent increase from the third quarter of 2006. On a per barrel of oil equivalent basis, production expenses increased seven percent to $9.92 in the fourth quarter of 2006 compared to $9.26 in the prior quarter. The quarterly increase in per unit costs reflected the impact of prior period natural gas processing adjustments, well servicing, water hauling and repairs and maintenance costs.

- General and administrative expenses increased slightly in the fourth quarter by $0.09 million over the third quarter of 2006. This is a five percent increase compared to the prior quarter and is primarily due to amounts recorded for year end performance-based compensation for employees.

- Interest and financing charges in the fourth quarter were $0.47 million, an increase of 26 percent or $0.10 million from the prior quarter. The average debt level for the fourth quarter increased 28 percent to $27.51 million compared to $21.49 million in the third quarter of 2006, resulting in increased debt servicing charges.

- Capital and current income taxes increased by $0.21 million from the third quarter of 2006. The increase was primarily due to Canadian withholding taxes and an increase in United States current income taxes.

Net earnings for the quarter decreased $5.26 million to $7.05 million, a 43 percent decrease compared to the third quarter 2006 net earnings of $12.31 million. Net earnings track the funds flow from operations for the respective periods modified by non-cash charges, which included the following for the fourth quarter of 2006:

- Unit-based compensation expense increased by $0.07 million during the fourth quarter of 2006 to $0.62 million, a 13 percent increase over the third quarter. The increase is a result of additional unit rights granted in the fourth quarter of 2006.

- Depletion and depreciation expense increased by $0.70 million to $10.86 million in the fourth quarter. The additional expense resulted from the use of an updated depletion and depreciation rate of $14.11 per barrel of oil equivalent, compared to the prior quarter's $13.48 per barrel of oil equivalent charge. The increased per unit charges are calculated on the basis of the recently completed 2006 year end reserve appraisal prepared by independent engineers that reflects Zargon's and the ongoing industry's trend to higher finding and development costs. Furthermore, 2006 depletion and depreciation rates continue to increase quarterly as a result of ongoing increases in the property and equipment balance from the conversion of exchangeable shares due to the application of EIC-151.

- Unrealized risk management gains in the 2006 fourth quarter of $0.80 million were 87 percent lower than the third quarter gains of $6.27 million. These unrealized gains result from "marking-to-market" financial risk management contracts at each period end. During the fourth quarter, unrealized risk management gains resulted from weaker commodity pricing at the December 31, 2006 mark-to-market date when compared to the third quarter September 30, 2006 mark-to-market date. In particular, lower year end futures oil pricing resulted in unrealized contract gains of $1.89 million, offset by natural gas losses of $1.09 million due to the realization and the expiry of certain financial natural gas contracts.

- Future income tax recovery was $0.79 million during the quarter, compared to a future income tax expense of $1.17 million from the third quarter of 2006. The future income tax recovery in the 2006 fourth quarter was due to the significant decrease of earnings before taxes to $8.22 million from the third quarter earnings before taxes of $15.73 million. Summarized, the fourth quarter decrease in net earnings was primarily derived by the decrease of non-cash unrealized risk management contract gains and increased field costs.

- Reduction in earnings due to non-controlling interests pertaining to exchangeable shares decreased to $1.30 million in the 2006 fourth quarter, from $1.80 million in the third quarter. This was due to a decrease in net earnings before non-controlling interest in the fourth quarter.

Net capital expenditures were $20.41 million during the fourth quarter of 2006, a seven percent increase from the prior quarter amount of $18.99 million. During the fourth quarter, Zargon completed an extensive field capital program focused on Alberta Plains core area natural gas well down-spacing and step-out drilling program and a Williston Basin core area horizontal oil well program. During the fourth quarter of 2006, 33.4 net wells were drilled, compared to 19.9 net wells in the third quarter of 2006.

Cash distributions to unitholders declared for the quarter totalled $9.05 million, resulting in a quarterly payout ratio of 48 percent of funds flow from operations or 55 percent on a per diluted trust unit basis.

ADDITIONAL INFORMATION

Additional information regarding the Trust and its business operations, including the Trust's Annual Information Form for December 31, 2006, is available on the Trust's SEDAR profile at www.sedar.com.

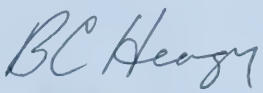
MANAGEMENT'S REPORT

The consolidated financial statements of Zargon Energy Trust were prepared by management in accordance with Canadian generally accepted accounting principles. The financial and operating information presented in this annual report is consistent with that shown in the consolidated financial statements.

Management has designed and maintains a system of internal accounting controls that provide reasonable assurance that all transactions are accurately recorded, that the financial statements reliably report the Trust's operations and that the Trust's assets are safeguarded. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. Such estimates are based on careful judgments made by management.

Ernst & Young LLP, an independent chartered accountant firm, was appointed by a resolution of the unitholders to audit the consolidated financial statements of the Trust and provide an independent opinion. They have conducted an independent examination of the Trust's accounting records in order to express their opinion on the consolidated financial statements.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through its Audit Committee. The Audit Committee, which consists of non-management directors, has met with Ernst & Young LLP and management in order to determine that management has fulfilled its responsibilities in the preparation of the consolidated financial statements. The Audit Committee has reported its findings to the Board of Directors, who have approved the consolidated financial statements.



C.H. Hansen
President and Chief Executive Officer

Calgary, Canada
March 12, 2007

AUDITORS' REPORT

To the Unitholders of Zargon Energy Trust

We have audited the consolidated balance sheets of Zargon Energy Trust as at December 31, 2006 and 2005 and the consolidated statements of earnings and accumulated earnings and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Calgary, Canada
March 12, 2007

Chartered Accountants

CONSOLIDATED BALANCE SHEETS

As at December 31 ($ thousand)	2006	2005
ASSETS [note 5]		
Current		
Accounts receivable [note 11]	**18,362**	21,835
Prepaid expenses and deposits	**3,281**	2,710
Unrealized risk management asset [note 11]	**5,817**	-
	27,460	24,545
Property and equipment, net [notes 3 and 4]	**283,108**	253,315
	310,568	277,860
LIABILITIES		
Current		
Accounts payable and accrued liabilities	**28,410**	30,570
Cash distributions payable [note 17]	**3,022**	11,122
Unrealized risk management liability [note 11]	**20**	3,756
	31,452	45,448
Long term debt [note 5]	**30,037**	10,339
Asset retirement obligations [note 6]	**17,307**	15,859
Future income taxes [note 9]	**47,891**	48,928
	126,687	120,574
Commitments and contingencies [notes 11, 12 and 13]		
NON-CONTROLLING INTEREST		
Exchangeable shares [note 8]	**18,319**	12,673
UNITHOLDERS' EQUITY		
Unitholders' capital [note 7]	**82,868**	71,644
Contributed surplus [note 7]	**2,475**	1,347
Accumulated earnings	**164,267**	119,768
Accumulated cash distributions [note 17]	**(84,048)**	(48,146)
	165,562	144,613
	310,568	277,860

See accompanying notes to the consolidated financial statements.

On behalf of the Board:

J.O. McCutcheon
Director

K.D. Kitagawa
Director

CONSOLIDATED STATEMENTS OF EARNINGS AND ACCUMULATED EARNINGS

For the years ended December 31 ($ thousand, except per unit amounts)	2006	2005
REVENUE		
Petroleum and natural gas revenue	**154,039**	162,722
Unrealized risk management gain/(loss) [note 11]	**9,553**	(3,756)
Realized risk management loss	**(569)**	(7,754)
Royalties	**(33,431)**	(37,319)
	129,592	113,893
EXPENSES		
Production	**26,416**	24,035
General and administrative [note 18]	**6,973**	6,053
Unit-based compensation [note 7]	**1,856**	902
Interest and financing charges [note 5]	**1,532**	786
Unrealized foreign exchange (gain)/loss	**24**	(201)
Accretion of asset retirement obligations [note 6]	**1,244**	1,196
Depletion and depreciation	**41,136**	37,484
	79,181	70,255
EARNINGS BEFORE INCOME TAXES	**50,411**	43,638
INCOME TAXES [note 9]		
Current	**1,598**	1,801
Future (recovery)	**(2,824)**	474
	(1,226)	2,275
EARNINGS FOR THE YEAR BEFORE NON-CONTROLLING INTEREST	**51,637**	41,363
Non-controlling interest – exchangeable shares [note 8]	**(7,138)**	(5,994)
NET EARNINGS FOR THE YEAR	**44,499**	35,369
ACCUMULATED EARNINGS, BEGINNING OF YEAR	**119,768**	84,399
ACCUMULATED EARNINGS, END OF YEAR	**164,267**	119,768
NET EARNINGS PER UNIT [note 10]		
Basic	**2.68**	2.21
Diluted	**2.68**	2.19

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 ($ thousand)	2006	2005
OPERATING ACTIVITIES		
Net earnings for the year	**44,499**	35,369
Add (deduct) non-cash items:		
Non-controlling interest – exchangeable shares	**7,138**	5,994
Unrealized risk management (gain)/loss	**(9,553)**	3,756
Depletion and depreciation	**41,136**	37,484
Accretion of asset retirement obligations	**1,244**	1,196
Unit-based compensation	**1,856**	902
Unrealized foreign exchange (gain)/loss	**24**	(201)
Future income taxes (recovery)	**(2,824)**	474
	83,520	84,974
Asset retirement expenditures	**(627)**	(604)
Changes in non-cash working capital [note 14]	**842**	(1,401)
	83,735	82,969
FINANCING ACTIVITIES		
Advances (repayment) of bank debt	**19,698**	(3,891)
Cash distributions to unitholders	**(35,902)**	(37,444)
Exercise of unit rights	**4,018**	2,723
Changes in non-cash working capital [note 14]	**(8,099)**	8,974
	(20,285)	(29,638)
INVESTING ACTIVITIES		
Additions to property and equipment	**(67,909)**	(55,986)
Proceeds on disposal of property and equipment	**4,543**	2,446
Changes in non-cash working capital [note 14]	**(84)**	209
	(63,450)	(53,331)
CHANGE IN CASH, AND CASH	**–**	–

See supplementary information contained in note 15.

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2006 and 2005.
All amounts are stated in Canadian dollars unless otherwise noted.

1. STRUCTURE OF THE TRUST

On July 15, 2004, Zargon Oil & Gas Ltd. (the "Company") was reorganized into Zargon Energy Trust (the "Trust" or "Zargon") as part of a Plan of Arrangement (the "Arrangement"). Shareholders of the Company received one trust unit or one exchangeable share for each common share held. The unitholders of the Trust are entitled to receive cash distributions paid by the Trust. Holders of exchangeable shares are not eligible to receive cash distributions paid, but rather, on each payment of a distribution, the number of trust units into which each exchangeable share is exchangeable is increased on a cumulative basis in respect of the distribution. The Trust is an unincorporated open-end investment trust established under the laws of the Province of Alberta and was created pursuant to a trust indenture ("Trust Indenture").

The Trust's principal business activity is the exploration for and development and production of petroleum and natural gas in Canada and the United States ("US").

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation and Basis of Presentation

These consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. Because a precise determination of many assets and liabilities is dependent upon future events, the preparation of periodic financial statements necessarily involves the use of estimates and approximations. Accordingly, actual results could differ from those estimates. The consolidated financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the Trust's accounting policies summarized below.

The consolidated financial statements include the accounts of Zargon Energy Trust, all subsidiaries and a partnership. All subsidiaries and the partnership are directly or indirectly owned and their operations are fully reflected in the consolidated financial statements.

Revenue Recognition

Petroleum and natural gas revenue is recognized in earnings when reserves are produced and delivered to the purchaser.

Joint Operations

The majority of the petroleum and natural gas operations of the Trust are conducted jointly with others, and accordingly, these consolidated financial statements reflect only the proportionate interests of the Trust in such activities.

Petroleum and Natural Gas Properties

The Trust follows the full cost method of accounting for its oil and natural gas operations whereby all costs relating to the acquisition, exploration and development of oil and natural gas reserves are capitalized and accumulated in separate cost centres for Canada and the United States. Such costs include land acquisition costs, annual carrying charges of non-producing properties, geological and geophysical costs, and costs of drilling and equipping wells.

Depletion and depreciation of petroleum, natural gas properties and equipment is computed using the unit of production method based on the estimated proved reserves of petroleum and natural gas before royalties determined by independent consultants. For purposes of this calculation, reserves are converted to common units on the basis that six thousand cubic feet of natural gas is equivalent to

one barrel of oil. A portion of the cost of petroleum and natural gas rights relating to undeveloped properties is excluded from the depletion calculation. Twenty percent of the year end balance of these costs is added to the depletion base each year. Proceeds on the disposal of petroleum and natural gas properties are applied against capitalized costs, with gains or losses not ordinarily recognized, unless such a disposal would result in a change in the depletion rate of 20 percent or more.

Depreciation of office equipment is provided using the declining balance method at an annual rate of 20 percent.

Impairment Test

The Trust applies an impairment test to petroleum, natural gas properties and equipment costs on a quarterly basis or more frequently as events or circumstances dictate. This impairment test is performed on both the Canadian and US cost centres. An impairment loss exists when the carrying amount of the Trust's petroleum, natural gas properties and equipment exceeds the estimated undiscounted future net cash flows associated with the Trust's proved reserves (before royalties). If an impairment loss is determined to exist, the costs carried on the balance sheet in excess of the fair value of the Trust's proved and probable reserves are charged to income. Reserves are determined pursuant to evaluation by independent engineers as dictated by National Instrument 51-101.

Asset Retirement Obligations

Zargon recognizes the fair value of an Asset Retirement Obligation ("ARO") in the period in which it is incurred when a reasonable estimate of the fair value can be made. The fair value of the estimated ARO is recorded as a liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on the unit of production method based on proved reserves (before royalties). The liability amount is increased each reporting period due to the passage of time and the amount of accretion is expensed in the period. Actual costs incurred upon the settlement of the ARO are charged against the liability. Differences between the actual costs incurred and the fair value of the liability recorded are recognized to earnings in the period incurred.

Financial Instruments

Derivative financial instruments are utilized to reduce commodity price risk associated with the Trust's production of oil and natural gas. The base prices for the commodities are sometimes denominated in US dollars and the Trust may also use such financial instruments to reduce the related foreign currency risk. Financial instruments may also be used from time to time to reduce interest rate risk on outstanding debt. The Trust does not enter into financial instruments for trading or speculative purposes.

The Trust follows a policy of using risk management instruments such as fixed price swaps, forward sales, puts and costless collars. The objective is to partially offset or mitigate the wide price swings commonly encountered in oil and natural gas commodities and in so doing protect a minimum level of cash flow in periods of low commodity prices.

For financial risk management contracts entered into prior to December 31, 2004, the Trust's policy was to designate each derivative financial instrument employed as a hedge of a specific portion of projected production over the term of the instrument. The Trust formally documented its risk management objectives and strategies for undertaking the hedged transactions, the hedging item, the nature of the specific risk exposures being hedged, the intended term of the hedge relationship, the method for assessing effectiveness and the method of accounting for the hedging relationship. The effectiveness of the derivative was assessed on an ongoing basis to ensure that the derivatives entered into were highly effective in offsetting changes in fair values of the hedged items. The instruments employed could have been denominated in US or Canadian dollars. Gains or losses from all hedging contracts, other than forward sales settled by physical delivery, were recognized as hedging gains or losses when the sale of hedged production occurred. The Trust believed these derivative financial instruments used were

effective as hedges over their term. In the event that a designated hedged item ceased to exist, any realized or unrealized gain or loss on such derivative commodity instruments were to be recognized in income immediately. If the hedge relationship was terminated, either via ineffectiveness or via termination of the designation, gains or losses previously deferred continued to be deferred and recognized when they were realized. As at June 30, 2006, all designated hedge contracts had expired.

For financial risk management contracts entered into after December 31, 2004, the Trust does consider these contracts to be effective on an economic basis but has decided not to designate these contracts as hedges for accounting purposes and, accordingly, for outstanding contracts not designated as hedges, an unrealized gain or loss is recorded based on the fair value (mark-to-market) of the contracts at the period end. These instruments have been recorded as an unrealized risk management asset/liability in the consolidated balance sheets.

In the case of forward sales, the instrument can sometimes be satisfied by physical delivery. In the case of physical delivery, the payment is recorded as part of the normal revenue stream.

Foreign currency swap agreements may be used from time to time to manage the risk inherent in producing commodities whose price is based directly or indirectly on US dollars, using a notional principal amount equal to the projected monthly revenue from their sale. Payments or charges are calculated and paid according to the terms of the agreement, usually with monthly settlement. At December 31, 2006 and 2005 the Trust had no such financial instruments.

Income Taxes

The Trust follows the liability method of tax allocation in accounting for income taxes. Under this method, the Trust records future income taxes for the effect of any differences between the accounting and income tax basis of an asset or liability using income tax rates expected to apply in the years in which these temporary differences are expected to be recovered or settled. The effect on future income tax assets and liabilities of a change in tax rates is recognized in net earnings in the period in which the change is substantively enacted.

Foreign Currency Translation

The Trust uses the temporal method of foreign currency translation whereby the monetary assets and liabilities recorded in a foreign currency are translated into Canadian dollars at year end exchange rates, and non-monetary assets and liabilities at the exchange rates prevailing when the assets were acquired or liability incurred. Revenues and expenses are translated at the average rate of exchange for the year. Gains and losses on translation are included in the consolidated statements of earnings.

Unit Rights and Unit-Based Compensation

Under the Trust's unit rights incentive plan (the "Plan"), rights to purchase trust units are granted to directors, officers and employees at current market prices. The Plan allows for the exercise price of rights to be reduced in future periods by an amount that distributions exceed a stated return on assets. Under the fair value method of accounting for unit-based compensation the cost of the option is charged to earnings with an offsetting amount recorded to contributed surplus, based on an estimate of the fair value using a Black-Scholes option-pricing model. Forfeiture of rights are recorded as a reduction in expense in the period in which they occur.

Per Unit Amounts

Per unit amounts are calculated using the weighted average number of trust units outstanding during the period. Diluted per unit amounts are calculated using the treasury stock method to determine the dilutive effect of unit-based compensation. The Trust follows the treasury stock method, which assumes that the proceeds received from "in-the-money" trust unit rights and unrecognized future unit-based compensation expense are used to repurchase units at the average market rate during the period. Diluted per unit amounts also include exchangeable shares using the "if-converted" method, whereby it is assumed the conversion of the exchangeable securities occurs at the beginning of the reporting period (or at the time of issuance if later).

Measurement Uncertainty

The amounts recorded for depletion and depreciation of property and equipment and the assessment of these assets for impairment are based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements of changes in such estimates in future periods could be material.

Inherent in the fair value calculation of asset retirement obligations, are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal and regulatory environments. To the extent future revisions to these assumptions impact the fair value of the existing asset retirement obligation liability, a corresponding adjustment is made to the property and equipment balance.

Cash Distributions

The Trust declares monthly distributions of cash to unitholders of record on the last day of each calendar month. Pursuant to the Trust's policy, it will pay distributions to its unitholders subject to satisfying its financing covenants. Such distributions are recorded as distributions of equity upon declaration of the distribution.

3. ACQUISITION

On November 15, 2005, a subsidiary of the Trust acquired all of the outstanding shares of Simoil Resources Ltd. ("Simoil"), a private oil and gas company, for consideration of $1.19 million. Consideration consisted of $0.04 million cash and the issuance of 40,000 Zargon trust units valued at $28.60 per unit.

The results of operations for Simoil have been included in the consolidated financial statements since November 15, 2005.

The acquisition was accounted for by the purchase method as follows:

($ thousand)	2005
Property and equipment	1,702
Future income tax liability	(415)
Asset retirement obligations	(101)
Total consideration	1,186

4. PROPERTY AND EQUIPMENT

($ thousand)	December 31, 2006 Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum, natural gas properties and equipment*	457,865	175,585	282,280
Office equipment	1,841	1,013	828
	459,706	176,598	283,108

($ thousand)	December 31, 2005 Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum, natural gas properties and equipment*	387,113	134,614	252,499
Office equipment	1,664	848	816
	388,777	135,462	253,315

** As a result of shareholders redeeming exchangeable shares, property and equipment has cumulatively increased $42.94 million, $6.73 million relating to 2006, $24.93 million relating to 2005 and $11.28 million relating to 2004. The effect of these increases has resulted in additional depletion and depreciation expense of approximately $10.56 million, $5.48 million relating to 2006 and $5.08 million relating to 2005.*

At December 31, 2006, petroleum, natural gas properties and equipment include $20.99 million (2005 – $14.72 million) relating to undeveloped properties that have been excluded from the depletion calculation.

An impairment test calculation was performed on the Trust's petroleum, natural gas properties and equipment at December 31, 2006 in which the estimated undiscounted future net cash flows associated with the proved reserves exceeded the carrying amount of the Trust's petroleum, natural gas properties and equipment. This impairment calculation was performed separately on both the Canadian and US cost centres.

The following table outlines benchmark prices used in the impairment test at December 31, 2006:

Year	WTI Crude Oil ($US/bbl)	Exchange Rate ($US/$Cdn)	WTI Crude Oil ($Cdn/bbl)	AECO Gas ($Cdn/gj)
2007	66.26	0.88	75.30	6.65
2008	68.20	0.88	77.50	7.71
2009	67.06	0.88	76.21	7.67
2010	65.44	0.88	74.36	7.37
2011	65.08	0.88	73.95	7.07
Thereafter (inflation %)	2.0%	0.88	2.0%	2.0%

Actual prices used in the impairment test were adjusted for commodity price differentials specific to Zargon.

5. LONG TERM DEBT

On September 30, 2005, a Canadian subsidiary and a US subsidiary of the Trust entered into syndicated committed credit facilities with a borrowing base of $80 million which replaced its former demand facility of $50 million. These facilities consisted of a $60 million tranche available to the Canadian borrower and a US $15 million tranche available to the US borrower. On June 30, 2006, Zargon amended and renewed these syndicated committed credit facilities, the result of which is an increase in the available facilities and borrowing base to $100 million from the previous amount of $80 million. These facilities consist of an $80 million tranche available to the Canadian borrower and a US $15 million tranche available to the US borrower. A $150 million demand debenture on the assets of the subsidiaries of the Trust has been provided as security for these facilities. The facilities are fully

revolving for a 364 day period with the provision for an annual extension at the option of the lenders and upon notice from Zargon's management. The next renewal date is July 31, 2007. Should the facilities not be renewed, they convert to one year non-revolving term facilities at the end of the revolving 364 day period. Repayment would not be required until the end of the non-revolving term, and as such, these facilities have been classified as long term debt. Interest rates fluctuate under the syndicated facilities with Canadian prime, US prime, and US base rates plus an applicable margin between zero basis points and 25 basis points, as well as with Canadian banker's acceptance and LIBOR rates plus an applicable margin between 90 basis points and 150 basis points. At December 31, 2006, $30.04 million (2005 – $10.34 million) had been drawn on the syndicated committed credit facilities bearing interest at Canadian prime (December 31, 2006 – 6.0 percent; December 31, 2005 – 5.0 percent) with any unused amounts subject to standby fees. In the normal course of operations Zargon enters into various letters of credit. At December 31, 2006, the approximate value of outstanding letters of credit totalled $0.47 million (2005 – $0.47 million).

6. ASSET RETIREMENT OBLIGATIONS

The total future asset retirement obligation was estimated by management based on Zargon's net working interest in all wells and facilities, estimated costs to reclaim and abandon wells and facilities and the estimated timing of the costs to be incurred in future periods. Zargon has estimated the net present value of its total asset retirement obligations to be $17.31 million as at December 31, 2006 (2005 – $15.86 million), based on a total future liability of $65.08 million (2005 – $62.54 million). These payments are expected to be made over the next 30 years with the majority of the costs being incurred after 2012. Commencing July 1, 2005, incremental asset retirement obligations are calculated using a revised credit adjusted risk-free rate of 7.5 percent. Asset retirement obligations prior to this period were calculated using a credit adjusted risk-free rate of 8.5 percent. An inflation rate of two percent used in the calculation of the present value of the asset retirement obligation remains unchanged. The following table reconciles Zargon's asset retirement obligations:

	Year Ended December 31,	
($ thousand)	**2006**	2005
Balance, beginning of year	**15,859**	14,390
Net liabilities incurred	**826**	906
Liabilities settled	**(627)**	(604)
Accretion expense	**1,244**	1,196
Foreign exchange	**5**	(29)
Balance, end of year	**17,307**	15,859

7. UNITHOLDERS' EQUITY

Pursuant to the Plan of Arrangement on July 15, 2004, 14.87 million units of the Trust and 3.66 million exchangeable shares (see note 8) of the Company were issued in exchange for all of the outstanding shares of the Company on a one-for-one basis.

The Trust is authorized to issue an unlimited number of voting trust units.

(thousand)	December 31, 2006 Number of Units	December 31, 2006 Amount ($)	December 31, 2005 Number of Units	December 31, 2005 Amount ($)
Balance, beginning of year	**16,355**	**71,644**	15,341	45,755
Unit rights exercised for cash	**208**	**4,018**	153	2,723
Unit-based compensation recognized on exercise of unit rights	**–**	**728**	–	725
Issued on conversion of exchangeable shares	**226**	**6,478**	821	21,297
Issued on corporate acquisition [note 3]	**–**	**–**	40	1,144
Balance, end of year	**16,789**	**82,868**	16,355	71,644

The Trust has a unit rights incentive plan (the "Plan") that allows the Trust to issue rights to acquire trust units to directors, officers, employees and other service providers. The Trust is authorized to issue up to 1.82 million unit rights; however, the number of trust units reserved for issuance upon exercise of the rights shall not at any time exceed 10 percent of the aggregate number of issued and outstanding trust units of the Trust. At the time of grant, unit right exercise prices approximate the market price for the trust units. At the time of exercise, the rights holder has the option of exercising at the original grant price or the exercise price as calculated per the Arrangement. Rights granted under the Plan generally vest over a three-year period and expire approximately five years from the grant date. Zargon uses a fair value methodology to value the unit rights grants.

The following table summarizes information about the Trust's unit rights:

	December 31, 2006 Number of Unit Rights (thousand)	December 31, 2006 Weighted Average Exercise Price ($/unit right)	December 31, 2005 Number of Unit Rights (thousand)	December 31, 2005 Weighted Average Exercise Price ($/unit right)
Outstanding at beginning of year	**915**	**22.80**	579	17.79
Unit rights granted	**518**	**29.70**	505	26.89
Unit rights exercised	**(208)**	**19.30**	(153)	17.77
Unit rights cancelled	**(17)**	**25.59**	(16)	18.13
Outstanding at end of year	**1,208**	**26.32**	915	22.80
Unit rights exercisable at year end	**212**	**24.11**	48	17.70

The following table summarizes information about unit rights outstanding at December 31, 2006:

	Unit Rights Outstanding			Unit Rights Exercisable	
Range of Exercise Prices ($/unit right)	Number Outstanding at 12/31/06 (thousand)	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price ($/unit right)	Number Exercisable at 12/31/06 (thousand)	Weighted Average Exercise Price ($/unit right)
17.70 – 19.25	**239**	**2.1 years**	**17.77**	**70**	**17.70**
22.00 – 25.06	**281**	**3.6 years**	**23.45**	**42**	**22.10**
27.40 – 29.93	**272**	**3.5 years**	**28.55**	**45**	**27.40**
31.09 – 33.05	**416**	**3.7 years**	**31.74**	**55**	**31.09**
	1,208		**26.32**	**212**	**24.11**

Unit-Based Compensation

The weighted average assumptions made for unit rights granted for 2006 include a volatility factor of expected market price of 26.6 percent, a risk-free interest rate of 4.1 percent, a dividend yield of 7.4 percent and an expected life of the unit rights of four years. These unit rights, together with the continued vesting of unit rights granted in prior years resulted in unit-based compensation expense in 2006 of $1.86 million (2005 – $0.90 million).

Compensation expense associated with rights granted under the Plan is recognized in earnings over the vesting period of the Plan with a corresponding increase in contributed surplus. The exercise of trust unit rights is recorded as an increase in trust units with a corresponding reduction in contributed surplus. Forfeiture of rights are recorded as a reduction in expense in the period in which they occur.

The following table summarizes information about the Trust's contributed surplus account:

Contributed Surplus

($ thousand)	
Balance, December 31, 2004	1,170
Unit-based compensation expense	902
Unit-based compensation recognized on exercise of unit rights	(725)
Balance, December 31, 2005	**1,347**
Unit-based compensation expense	**1,856**
Unit-based compensation recognized on exercise of unit rights	**(728)**
Balance, December 31, 2006	**2,475**

Unit Redemption

Under the terms of the Trust Indenture, unitholders may require the Trust to redeem all or any part of the trust units at a price and under certain terms and conditions as specified in the Trust Indenture. The redemption price per trust unit will be equal to the lesser of: (i) 90 percent of the "market price" of the trust units on the principal market on which the trust units are quoted for trading during the 10 trading day period commencing immediately after the date on which the trust units are tendered to Zargon for redemption; and (ii) the closing market price on the principal market on which the trust units are quoted for trading on the date that the trust units are so tendered for redemption. Trust units tendered for redemption in any calendar month shall be paid on the last day of the third following month by, at the Trust's option: (i) a cash payment; or (ii) a distribution of notes and/or redemption notes. It is anticipated that this redemption right will not be the primary mechanism for holders of trust units to dispose of their trust units. Notes or redemption notes which may be distributed in specie to unitholders in connection with a redemption will not be listed on any stock exchange and no market is expected to develop for such notes or redemption notes. Notes or redemption notes may not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans. To date, no trust units have been tendered for redemption.

8. NON-CONTROLLING INTEREST-EXCHANGEABLE SHARE

Zargon Oil & Gas Ltd. is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares are convertible into trust units at the option of the shareholder, based on the exchange ratio, which is adjusted monthly to reflect the distribution paid on the trust units. Cash distributions are not paid on the exchangeable shares. During the year, a total of 0.20 million (2005 – 0.78 million) exchangeable shares were converted into 0.23 million (2005 – 0.82 million) trust units based on the exchange ratio at the time of conversion. At December 31, 2006, the exchange ratio was 1.19403 (December 31, 2005 – 1.09629) trust units per exchangeable share. As set out in the

Arrangement, the exchangeable shares are entitled to vote equally to the number of trust units for which each exchangeable share is convertible into a trust unit on the record date. The Board of Directors of Zargon Oil & Gas Ltd. hold the option to redeem all outstanding exchangeable shares for trust units on or before July 15, 2014. At such time, should the Board not extend the term of the shares, there would be no remaining non-controlling interest.

Pursuant to EIC-151 "Exchangeable Securities Issued by a Subsidiary of an Income Trust", if certain conditions are met, the exchangeable shares issued by a subsidiary must be reflected as non-controlling interest on the consolidated balance sheets and in turn, net earnings must be reduced by the amount of net earnings attributed to the non-controlling interest.

The non-controlling interest on the consolidated balance sheets consists of the book value of exchangeable shares at the time of the Plan of Arrangement, plus net earnings attributable to the exchangeable shareholders, less exchangeable shares (and related cumulative earnings) redeemed. The net earnings attributable to the non-controlling interest on the consolidated statements of earnings represents the cumulative share of net earnings attributable to the non-controlling interest based on the trust units issuable for exchangeable shares in proportion to total trust units issued and issuable each period end.

[illegible]st – Exchangeable Shares

(thousand, except exchange ratio)	**December 31, 2006** Number of Shares	**Amount ($)**	December 31, 2005 Number of Shares	Amount ($)
Balance, beginning of year	**2,402**	**12,673**	3,186	9,529
Exchanged for trust units at book value and including earnings attributed since Plan of Arrangement	**(195)**	**(1,492)**	(784)	(2,850)
Earnings attributable to non-controlling interest	**–**	**7,138**	–	5,994
Balance, end of year	**2,207**	**18,319**	2,402	12,673
Exchange ratio, end of year	**1.19403**		1.09629	
Trust units issuable upon conversion of exchangeable shares, end of year	**2,635**		2,633	

The proforma total units outstanding at December 31, 2006, including trust units outstanding, and trust units issuable upon conversion of exchangeable shares and after giving rise to the exchange ratio at the end of the year is 19.42 million units (2005 – 18.99 million units).

The effect of EIC-151 on Zargon's unitholders' capital and exchangeable shares is as follows:

($ thousand)	Zargon Energy Trust Units	Zargon Oil & Gas Ltd. Exchangeable Shares	Total
Balance at December 31, 2004	45,755	9,529	55,284
Issued on redemption of exchangeable shares at book value	1,909	(1,909)	–
Effect of EIC-151	19,388	5,053	24,441
Unit-based compensation recognized on exercise of unit rights	725	–	725
Unit rights exercised for cash	2,723	–	2,723
Issued on corporate acquisition	1,144	–	1,144
Balance at December 31, 2005	**71,644**	**12,673**	**84,317**
Issued on redemption of exchangeable shares at book value	**477**	**(477)**	**–**
Effect of EIC-151	**6,001**	**6,123**	**12,124**
Unit-based compensation recognized on exercise of unit rights	**728**	**–**	**728**
Unit rights exercised for cash	**4,018**	**–**	**4,018**
Balance at December 31, 2006	**82,868**	**18,319**	**101,187**

On January 19, 2005, the CICA issued EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" that states that exchangeable securities issued by a subsidiary of an Income Trust should be reflected as either a non-controlling interest or debt on the consolidated balance sheets unless they meet certain criteria. The exchangeable shares issued by Zargon Oil & Gas Ltd., a corporate subsidiary of the Trust, are publicly traded and have an expiry term, which could be extended at the option of the Board of Directors. Therefore, these securities are considered, by EIC-151, to be transferable to third parties and to have an indefinite life. EIC-151 states that if these criteria are met, the exchangeable shares should be reflected as a non-controlling interest. Prior to 2005, these exchangeable shares were reflected as a component of unitholders' equity.

As a result of EIC-151, the Trust has increased its unitholders' equity and non-controlling interest for 2006 by $12.12 million (2005 – $24.44 million) on the Trust's consolidated balance sheet. Consolidated net earnings for 2006 have been reduced for net earnings attributable to the non-controlling interest of $7.14 million (2005 – $5.99 million). In accordance with EIC-151 and given the circumstances in Zargon's case, each redemption is accounted for as a step-purchase, which for 2006 additionally resulted in an increase in property and equipment of $6.73 million (2005 – $24.93 million), and an increase in future income tax liability of $1.75 million (2005 – $6.48 million). Funds flow from operations were not impacted by this change.

The cumulative impact to date of the application of EIC-151 has been to increase gross property and equipment by $42.94 million, (for depletion impact see note 4), unitholders' equity and non-controlling interest by $46.71 million, future income tax liability by $11.23 million and an allocation of net earnings to exchangeable shareholders' of $15.00 million.

9. INCOME TAXES

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unitholders. As the Trust allocates all of its Canadian taxable income to the unitholders in accordance with the Trust Indenture, and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no current tax provision for Canadian income tax expense has been made in the Trust. Canadian large corporation tax, capital taxes, and US income taxes are provided for under current income tax expense.

In the Trust structure, payments are made between the Company and the Trust that result in the transferring of taxable income from the Company to individual unitholders. These payments may reduce future income tax liabilities previously recorded by the Company that would be recognized as a recovery of income tax in the period incurred.

On October 31, 2006, the Federal Government announced tax proposals pertaining to taxation of distributions paid by trusts and the personal tax treatment of trust distributions. Currently, the Trust does not pay tax on distributions as tax is paid by the unitholders. If enacted, the proposals would result in taxation of distributions at the Trust level at a rate of 31.5 percent effective January 1, 2011. As the proposals are not yet enacted, there was no impact on the results of the Trust for the year ended December 31, 2006. The Trust is currently assessing the proposals and the potential implications to the Trust.

Income taxes differ from the amounts which would be obtained by applying statutory income tax rates to earnings before income taxes as follows:

($ thousand)	**2006**	2005
Statutory income tax rate	**36.30%**	38.86%
Expected income taxes	**18,300**	16,958
Add (deduct) income tax effect of:		
Non-deductible Crown charges, net of Alberta Royalty Credit	**2,145**	5,058
Resource allowance	**(2,397)**	(5,062)
Rate adjustment	**(8,865)**	(1,674)
Cash distributions	**(13,032)**	(14,551)
Large corporation tax, capital taxes, and US income taxes	**1,598**	1,801
Other	**1,025**	(255)
	(1,226)	2,275

The future income tax provision for the year ended December 31, 2006 includes a recovery of $6.01 million relating to a reduction in future federal and provincial income tax rates substantively enacted and recorded during the 2006 second quarter. The Federal Government budget also eliminated the Canadian large corporation tax effective January 1, 2006.

Future income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of Zargon's net future income tax liability are as follows:

($ thousand)	**2006**	2005
Net book value of property and equipment in excess of tax pools	**46,336**	46,088
Deferred partnership earnings	**6,024**	10,178
Asset retirement obligations	**(6,333)**	(5,631)
Unrealized risk management asset/liability	**2,104**	(1,319)
Share issue costs	**(8)**	(19)
Alberta Royalty Credit	**(232)**	(369)
	47,891	48,928

As at December 31, 2006, Zargon's tax pools are as follows:

($ thousand)	December 31, 2006
Canadian oil and gas property expenses in the Trust	41,947
Canadian oil and gas property expenses in other entities	5,892
Canadian development expenses	24,681
Canadian exploration expenses	23,488
Capital cost allowance	30,161
US tax pools	4,555
Partnership deferral	(18,190)
Other	269
	112,803

10. WEIGHTED AVERAGE NUMBER OF TOTA

(thousand units)	2006	2005
Basic	16,600	16,003
Diluted	19,244	18,848

Dilution amounts of 2.64 million units (2005 – 2.85 million) were added to the weighted average number of units outstanding during the year in the calculation of diluted per unit amounts. These unit additions represent the dilutive effect of unit rights according to the treasury stock method, and also include exchangeable shares using the "if-converted" method. An adjustment to the numerator amount was required in the diluted calculation to provide for the earnings of $7.14 million (2005 – $5.99 million) attributable to the non-controlling interest pertaining to the exchangeable shareholders.

11. FINANCIAL INSTRUMENTS

Fair Value of Financial Assets and I

Financial instruments of the Trust consist of accounts receivable, deposits, accounts payable, cash distributions payable, unrealized risk management assets and liabilities and long term debt. As at December 31, 2006 and 2005, there are no significant differences between the carrying values of these amounts and their estimated market values.

Credit Risk Management

Accounts receivable include amounts receivable for petroleum and natural gas sales that are generally made to large credit-worthy purchasers, and amounts receivable from joint venture partners that are recoverable from production. Accordingly, management views credit risks on these amounts as low. Of Zargon's significant individual accounts receivable at December 31, 2006, approximately 26 percent was owing from one company (2005 – 32 percent).

The Trust is exposed to losses in the event of non-performance by counterparties to financial risk management contracts. The Trust minimizes credit risk associated with possible non-performance to these financial instruments by entering into contracts with only investment grade counterparties, limits on exposures to any one counterparty, and monitoring procedures. Management believes these risks are minimal.

Interest Rate Risk Management

Borrowings under bank credit facilities are market-rate-based (variable interest rates); thus carrying values approximate fair values.

Foreign Currency Risk Management

The Trust is exposed to fluctuations in the exchange rate between the Canadian dollar and the US dollar. Crude oil, and to a large extent natural gas prices, are based upon reference prices denominated in US dollars, while the majority of the Trust's expenses are denominated in Canadian dollars. When appropriate, the Trust enters into agreements to fix the exchange rate of Canadian dollars to US dollars in order to manage this risk.

Commodity Price Risk Management

The Trust is a party to certain financial instruments that have fixed the price of a portion of its oil and natural gas production. The Trust enters into these contracts for risk management purposes only, in order to protect a portion of its future cash flow from the volatility of oil and natural gas commodity prices. The Trust has outstanding contracts at December 31, 2006 as follows:

Financial Contracts at December 31, 2006:

	Rate	Weighted Average Price	Range of Terms	Fair Market Value Gain/(Loss) ($ thousand)
Oil swaps	500 bbl/d	$67.33 US/bbl	Jan. 1/07–Jun. 30/07	393
	500 bbl/d	$72.70 US/bbl	Jan. 1/07–Dec. 31/07	1,641
	500 bbl/d	$72.10 US/bbl	Jul. 1/07–Dec. 31/07	609
	300 bbl/d	$66.70 US/bbl	Jan. 1/08–Mar. 31/08	(20)
	300 bbl/d	$68.29 US/bbl	Apr. 1/08–Jun. 30/08	30
Natural gas swaps	3,000 gj/d	$9.13/gj	Jan. 1/07–Mar. 31/07	729
	4,000 gj/d	$8.47/gj	Apr. 1/07–Oct. 31/07	1,676
	1,000 gj/d	$8.77/gj	Nov. 1/07–Mar. 31/08	97
Natural gas collars	1,000 gj/d	$9.50/gj Put $12.50/gj Call	Jan. 1/07–Mar. 31/07	276
	1,000 gj/d	$10.50/gj Put $13.18/gj Call	Jan. 1/07–Mar. 31/07	366
Net Fair Market Value, Financial Contracts				**5,797**

Physical Contracts at December 31, 2006:

	Rate	Weighted Average Price	Range of Terms	Fair Market Value Gain/(Loss) ($ thousand)
Natural gas fixed price	2,000 gj/d	$9.23/gj	Jan. 1/07–Mar. 31/07	503
	1,000 gj/d	$7.88/gj	Apr. 1/07–Oct. 31/07	293
Natural gas collars	1,000 gj/d	$8.50/gj Put $12.85/gj Call	Jan. 1/07–Mar. 31/07	186
	1,000 gj/d	$9.50/gj Put $13.50/gj Call	Jan. 1/07–Mar. 31/07	276
Total Fair Market Value, Physical Contracts				**1,258**

Oil swaps and collars are settled against the NYMEX pricing index, whereas natural gas swaps and collars are settled against the AECO pricing index.

For financial risk management contracts, the Trust considers these contracts to be effective on an economic basis but has decided not to designate these contracts as hedges for accounting purposes and accordingly any unrealized gains or losses are recorded based on the fair value (mark-to-market) of the contracts at the period end. The unrealized gain for 2006 was $9.55 million and the unrealized loss for 2005 was $3.76 million.

Contracts settled by way of physical delivery are recognized as part of the normal revenue stream. These instruments have no book values recorded in the consolidated financial statements.

12. COMMITMENTS

The Trust is committed to future minimum payments for natural gas transportation contracts in addition to operating leases for office space, office equipment, vehicles and field equipment. Payments required under these commitments for each of the next five years are: 2007 – $1.93 million; 2008 – $1.39 million; 2009 – $1.25 million; 2010 – $1.21 million; 2011 – $1.21 million; thereafter – $0.70 million.

13. CONTINGENCIES AND GUARANTEES

In the normal course of operations, Zargon executes agreements that provide for indemnification and guarantees to counterparties in transactions such as the sale of assets and operating leases.

These indemnifications and guarantees may require compensation to counterparties for costs and losses incurred as a result of various events, including breaches of representations and warranties, loss of or damages to property, environmental liabilities or as a result of litigation that may be suffered by counterparties.

Certain indemnifications can extend for an unlimited period and generally do not provide for any limit on the maximum potential amount. The nature of substantially all of the indemnifications prevents the Trust from making a reasonable estimate of the maximum potential amount that might be required to pay counterparties as the agreements do not specify a maximum amount, and the amounts depend on the outcome of future contingent events, the nature and likelihood of which cannot be determined at this time.

The Trust indemnifies its directors and officers against any and all claims or losses reasonably incurred in the performance of their service to the Trust to the extent permitted by law. The Trust has acquired and maintains liability insurance for its directors and officers. The Trust is party to various legal claims associated with the ordinary conduct of business. The Trust does not anticipate that these claims will have a material impact on the Trust's financial position.

14. CHANGES IN NON-CASH WORKING CAPITAL

	Year Ended December 31,	
($ thousand)	**2006**	2005
Changes in non-cash working capital items:		
Accounts receivable	**3,473**	(7,560)
Prepaid expenses and deposits	**(571)**	243
Accounts payable and accrued liabilities	**(2,160)**	6,417
Cash distributions payable	**(8,100)**	8,912
Other	**17**	(230)
	(7,341)	7,782
Changes relating to operating activities	**842**	(1,401)
Changes relating to financing activities	**(8,099)**	8,974
Changes relating to investing activities	**(84)**	209
	(7,341)	7,782

15. SUPPLEMENTAL CASH FLOW INFORMATION

($ thousand)	2006	2005
Cash interest and financing charges paid	**1,593**	1,044
Cash taxes paid	**2,216**	1,911

16. SEGMENTED INFORMATION

Zargon's entire operating activities are related to exploration, development and production of oil and natural gas in the geographic segments of Canada and the US.

	2006		
($ thousand)	**Canada**	**United States**	**Combined**
Petroleum and natural gas revenue	**129,967**	**24,072**	**154,039**
Earnings before income taxes	**39,797**	**10,614**	**50,411**
Property and equipment, net	**248,440**	**34,668**	**283,108**
Total assets	**273,748**	**36,820**	**310,568**
Net capital expenditures	**58,040**	**5,326**	**63,366**

	2005		
($ thousand)	Canada	United States	Combined
Petroleum and natural gas revenue	141,869	20,853	162,722
Earnings before income taxes	34,890	8,748	43,638
Property and equipment, net	221,664	31,651	253,315
Total assets	244,416	33,444	277,860
Net capital expenditures[1]	49,251	5,433	54,684

1. Amounts include capital expenditures acquired for cash and equity issuances.

17. CASH DISTRIBUTIONS

During the year, the Trust declared distributions to the unitholders in the aggregate amount of $35.90 million (2005 – $37.44 million) in accordance with the following schedule:

2006 Distributions	Record Date	Distribution Date	Per Trust Unit
January	January 31, 2006	February 15, 2006	$0.18
February	February 28, 2006	March 15, 2006	$0.18
March	March 31, 2006	April 17, 2006	$0.18
April	April 30, 2006	May 15, 2006	$0.18
May	May 31, 2006	June 15, 2006	$0.18
June	June 30, 2006	July 17, 2006	$0.18
July	July 31, 2006	August 15, 2006	$0.18
August	August 31, 2006	September 15, 2006	$0.18
September	September 30, 2006	October 16, 2006	$0.18
October	October 31, 2006	November 15, 2006	$0.18
November	November 30, 2006	December 15, 2006	$0.18
December	December 31, 2006	January 15, 2007	$0.18

2005 Distributions	Record Date	Distribution Date	Per Trust Unit
January	January 31, 2005	February 15, 2005	$0.14
February	February 28, 2005	March 15, 2005	$0.14
March	March 31, 2005	April 15, 2005	$0.14
April	April 30, 2005	May 16, 2005	$0.14
May	May 31, 2005	June 15, 2005	$0.14
June	June 30, 2005	July 15, 2005	$0.14
July	July 31, 2005	August 15, 2005	$0.14
August	August 31, 2005	September 15, 2005	$0.16
September	September 30, 2005	October 17, 2005	$0.16
October	October 31, 2005	November 15, 2005	$0.16
November	November 30, 2005	December 15, 2005	$0.18
December	December 31, 2005	January 16, 2006	$0.18
December (Supplemental)	December 31, 2005	January 16, 2006	$0.50

18. RELATED PARTY TRANSACTIONS

Zargon paid $0.05 million (2005 – $0.04 million) for vehicle leases to a company owned by a Board member; $0.09 million (2005 – $0.12 million) for legal services to a law firm in which a Board member is a partner; $0.02 million (2005 – $0.01 million) for field services to a company of which a senior Zargon officer is a Board member and nominal shareholder; and $0.06 million (2005 – $0.13 million) in consulting fees to a company owned by the Chairman of the Board. These payments were in the normal course of operations, on commercial terms, and therefore were recorded at the exchange amount.

SIX-YEAR SUMMARY

($ thousand, except per unit amounts)	**2006**	2005	2004	2003	2002	2001
Petroleum and natural gas revenue	**154,039**	162,722	123,968	101,657	65,538	63,795
Less expenses – cash items						
Royalties	**33,431**	37,319	28,047	22,508	13,508	14,222
Production	**26,416**	24,035	21,692	17,201	15,649	11,933
General and administrative	**6,973**	6,053	4,358	3,542	3,455	3,083
Realized risk management (gain)/loss	**569**	7,754	4,568	2,882	(669)	573
Interest and financing charges	**1,532**	786	440	771	1,100	957
Current and capital taxes	**1,598**	1,801	1,114	406	378	358
Funds flow from operations	**83,520**	84,974	63,749	54,347	32,117	32,669
Less expenses – non-cash items						
Depletion, depreciation and foreign exchange	**41,160**	37,283	26,850	19,363	14,148	11,067
Unrealized risk management (gain)/loss	**(9,553)**	3,756	–	–	–	–
Future income tax (recovery)	**(2,824)**	474	9,639	9,187	6,558	7,860
Accretion of asset retirement obligations	**1,244**	1,196	1,076	1,172	715	520
Unit-based compensation	**1,856**	902	3,682	264	–	–
Earnings before non-controlling interest	**51,637**	41,363	22,502	24,361	10,696	13,222
Less non-controlling interest – exchangeable shares	**7,138**	5,994	1,870	–	–	–
Net earnings	**44,499**	35,369	20,632	24,361	10,696	13,222
Per unit, diluted						
Funds flow from operations	**4.34**	4.51	3.40	2.96	1.81	2.03
Net earnings	**2.68**	2.19	1.20	1.33	0.60	0.82
Net capital expenditures	**63,366**	54,684	56,273	39,909	35,548	55,176
Cash distributions	**35,902**	37,444	10,702	–	–	–
Cash distributions ($/trust unit)	**2.16**	2.32	0.70	–	–	–
Balance sheet at year end						
Property and equipment, net	**283,108**	253,315	209,736	167,888	147,404	124,020
Bank debt	**30,037**	10,339	14,230	6,978	25,279	24,137
Unitholders' equity	**165,562**	144,613	120,622	112,469	86,699	70,072
Unitholders' equity ($/total units)	**8.53**	7.62	6.48	6.25	4.92	4.20
Year end total units outstanding (thousand)	**19,424**	18,988	18,610	17,992	17,637	16,666

	2006	2005	2004	2003	2002	2001
OPERATING						
Total production (boe/d)	**8,422**	8,342	8,222	7,446	6,349	5,553
Oil and liquids (bbl/d)	**3,805**	3,697	3,416	3,287	2,968	2,441
Natural gas (mmcf/d)	**27.70**	27.87	28.84	24.95	20.29	18.67
Equivalent per million trust units (boe/d)	**437**	445	447	418	368	357
Total proved reserves (mboe)	**19,050**	19,243	19,049	18,664	21,592	20,320
Proved oil and liquids (mbbl)	**11,523**	11,490	10,954	10,505	11,114	10,482
Proved natural gas (bcf)	**45.15**	46.52	48.57	48.96	62.87	59.03
Total proved and probable reserves (mboe)	**27,464**	26,771	25,955	24,745	23,983	22,859
Proved and probable oil and liquids (mbbl)	**15,937**	15,354	14,361	13,566	12,445	11,948
Proved and probable natural gas (bcf)	**69.15**	68.50	69.56	67.07	69.23	65.47
Equivalent per total unit (boe)	**1.41**	1.41	1.39	1.38	1.36	1.37
Average selling price before the impact of financial risk management contracts						
WTI crude oil price ($US/bbl)	**66.22**	56.56	41.40	31.04	26.08	25.90
Edmonton par crude oil price ($Cdn/bbl)	**72.77**	68.72	52.54	43.14	39.94	39.18
Zargon realized crude oil price ($Cdn/bbl)	**61.25**	57.15	45.37	36.66	34.45	31.86
NYMEX average daily spot natural gas price ($US/mmbtu)	**6.75**	8.89	5.90	5.49	3.35	3.94
AECO average daily spot natural gas price ($Cdn/mmbtu)	**6.54**	8.77	6.55	6.70	4.18	5.43
Zargon realized natural gas price ($Cdn/mcf)	**6.82**	8.41	6.37	6.33	3.81	5.19
Other data						
Wells drilled, net	**76.2**	53.5	49.5	38.6	31.6	47.7
Undeveloped land (thousand net acres)	**381**	367	376	398	331	241
Closing trust unit price ($/unit)	**24.79**	31.75	23.85	13.50	9.00	7.20

NOTES:

Throughout this summary, the calculation of barrels of oil equivalent (boe) is based on the conversion ratio that six thousand cubic feet of natural gas is equivalent to one barrel of oil. For a further discussion about this term, refer to the Management's Discussion and Analysis section in this report.

Funds flow from operations is a non-GAAP term that represents net earnings except for non-cash items. For a further discussion about this term, refer to the Management's Discussion and Analysis section in this report.

For net capital expenditures, amounts include capital expenditures acquired for cash and equity issuances.

Cash distributions to unitholders commenced subsequent to the reorganization of the Company into a Trust effective July 15, 2004.

Total units outstanding include trust units plus exchangeable shares outstanding at year end. The exchangeable shares are converted at the exchange ratio at the end of the year.

Average daily production per million trust units is calculated using the weighted average number of units outstanding during the year, plus the weighted average number of exchangeable shares outstanding for the year converted at the average exchange ratio for the year.

In this table the established reserves (proved plus 50 percent probable) for the prior years (2001-2002) are used as a comparison to 2003, 2004, 2005 and 2006 proved and probable reserves. This adjustment is necessary due to the change in reserve risk assessments required to comply with NI 51-101 reserve guidelines.

Certain comparative period numbers reflect retroactive restatement due to a change in accounting policy.

CORPORATE INFORMATION

BOARD OF DIRECTORS

Craig H. Hansen
Calgary, Alberta

K. James Harrison[3] [4]
Oakville, Ontario

Kyle D. Kitagawa[1] [2]
Calgary, Alberta

James J. Lawson[1] [3]
Oakville, Ontario

John O. McCutcheon
Chairman of the Board
Vancouver, British Columbia

Margaret A. McKenzie[1]
Calgary, Alberta

Jim Peplinski[2] [4]
Calgary, Alberta

J. Graham Weir[1] [2]
Calgary, Alberta

Grant A. Zawalsky[3] [4]
Calgary, Alberta

OFFICERS

Craig H. Hansen
President and
Chief Executive Officer

Brent C. Heagy
Executive Vice President and
Chief Financial Officer

Daniel A. Roulston
Executive Vice President, Operations

Henry J. Baird
Vice President, Exploitation

Mark I. Lake
Vice President, Exploration

Sheila A. Wares
Vice President, Accounting

Kenneth W. Young
Vice President, Land

Jason B. Dranchuk
Controller and Treasurer

(1) Audit Committee
(2) Reserves Committee
(3) Governance and Nominating Committee
(4) Compensation Committee

STOCK EXCHANGE LISTING

The Toronto Stock Exchange

Zargon Energy Trust
Trust Units
Trading Symbol: ZAR.UN

Zargon Oil & Gas Ltd.
Exchangeable Shares
Trading Symbol: ZOG.B

TRANSFER AGENT

Valiant Trust Company
310, 606 - 4th Street S.W.
Calgary, Alberta T2P 1T1

BANKERS

The Toronto Dominion Bank
910, 333 - 7th Avenue S.W.
Calgary, Alberta T2P 2Z1

Canadian Imperial Bank of Commerce
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Calgary, Alberta T2P 2P2

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WEBSITE

www.zargon.ca

ANNUAL MEETING

The annual meeting of the Unitholders of Zargon Energy Trust will be held on Thursday, April 26, 2007 at 2:00 pm (Calgary time) in the Strand/Tivoli Room of the Metropolitan Conference Centre, 333 - 4th Avenue S.W., Calgary, Alberta.

ABBREVIATIONS

bbl	Barrel
bbl/d	Barrels per day
bcf	Billion cubic feet
boe	Barrels of oil equivalent (6 mcf is equivalent to 1 bbl)
boe/d	Barrels of oil equivalent per day
btu	British thermal units
F&D	Finding and development
FD&A	Finding, development and acquisition
gj	Gigajoule
gj/d	Gigajoules per day
m	Thousand
mm	Million
mcf	Thousand cubic feet
mcf/d	Thousand cubic feet per day
PV	Present value
PVBT	Present value before tax

Forward-Looking Statements

This document contains statements that are forward-looking, such as those relating to results of operations and financial condition, capital spending, financing sources, commodity prices, costs of production and the magnitude of oil and natural gas reserves. By their nature, forward-looking statements are subject to numerous risks and uncertainties that could significantly affect anticipated results in the future and, accordingly, actual results may differ materially from those predicted. The forward-looking statements contained in this annual report are as of March 12, 2007 and are subject to change after this date. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Zargon disclaims, except as required by law, any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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